89-196 (1)

NO. ________

IN THE
SUPREME COURT OF THE UNITED STATES
OCTOBER TERM, 1988

RAILROAD COMMISSION OF TEXAS,
Petitioner

V.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

On Petition For Writ Of Certiorari
To The United States Court Of Appeals
For The Tenth Circuit

BRIEF OF PETITIONER THE RAILROAD COMMISSION OF TEXAS

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QUESTIONS PRESENTED

1. Whether the Tenth Circuit Court of Appeals erred in upholding FERC Opinion No. 239 which improperly usurps the State's jurisdiction to regulate "production and gathering" of natural gas, as reserved for state regulation by Section l(b) of the Natural Gas Act, 15 U.S.C. § 717(b)?

2. Whether the Tenth Circuit Court of Appeals erred in upholding FERC Opinion No. 239 which improperly usurps the State's exclusive jursidiction to designate proration units in violation of Section 103 of the Natural Gas Policy Act of 1978, 15 U.S.C. § 3313?

3. Whether the Tenth Circuit Court of Appeals erred in not holding that FERC acted beyond its competence and abused its discretion by failing to defer to the Railroad Commission of Texas and Texas' State courts for final determination and interpreting of unsettled issues of Texas law?

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LIST OF ALL PARTIES

The following parties appeared in the proceedings before the Tenth Circuit Court of Appeals:

Anadarko Production Co.

Pan Eastern Exploration Co.

Cabot Pipeline Co.

Colorado Interstate Gas Co.

Conoco, Inc.

Lucky Bird Petroleum

Mobil Producing Texas and New Mexico, Inc.

Natural Gas Pipeline Co. of America

Northern Natural Gas Co.
a Division of Enron Corp.

Phillips Petroleum Co.

State of Texas

Railroad Commission of Texas

L.R. Spradling & V.T.Stowers
d/b/a/ Stowers Oil and Gas Co.

J.B. Watkins

Walker Operating Corp.

Dorchester Master Limited Partnership

Northern States Power Co.

Minnesota Department of Public Service

Texaco Producing, Inc.

Lake Superior District Power Co.

Iowa Public Service Co.

Inter-City Gas

Williams Natural Gas Co.

OPINIONS BELOW

The opinion of the United States Court of Appeals for the Tenth Circuit, reported at 874 F.2d 1320 (1989), appears as Exhibit A in the attached Appendix. FERC Opinion No. 239, reported at 32 FERC ¶ 61,043 (1985), appears as Exhibit B in the attached Appendix. The FERC Order denying Motions for Stay and Requests for Rehearing, reported at 33 FERC ¶ 61,207 (1985), appears as Exhibit C in the attached Appendix. The Administrative Law Judge's Recommended Decision adopted by FERC, reported at 30 FERC ¶ 63,017 (1985), appears as Exhibit D in the attached Appendix.

JURISDICTION

Judgment of the Court of Appeals affirming FERC's Opinion No. 239 was entered on April 28, 1989. No motion for rehearing was filed. Jurisdiction of this Court is invoked under 28 U.S.C. §1254(1).

STATUTORY PROVISIONS INVOLVED

Section l(b) of the Natural Gas Act, 15 U.S.C. §717 *et seq.*, as well as sections 2(8), 103 and 503 of the Natural Gas Policy Act, 15 U.S.C. §3301 *et seq.*, are involved in this cause. Various provisions contained in the Texas Natural Resources Code, §§ 85.001 *et seq.* and §§ 86.001 *et. seq.*, are also involved in this cause.

REASON FOR GRANTING THE WRIT

The issues presented in this Petition underscore the need for this Court to address the balance between state jurisdiction over production and gathering of natural gas and federal jurisdiction over the transportation and sale for resale of natural gas. To date, the courts have not clearly defined the line of demarcation between federal and state jurisdiction as contemplated under Section l(b) of the Natural Gas Act. ("NGA").

FERC's Opinion No. 239 directly interferes with Texas' system of regulation of mineral production in several of the largest oil and gas fields in the State. In administratively overruling the express provisions of the NGA, FERC ignored this Court's repeated admonitions that the regulation of production is a matter exclusively reserved to the states. In upholding FERC's action, the Tenth Circuit incorrectly concludes that FERC is simply regulating "pricing." Rather, FERC's Opinion No. 239 seeks to directly regulate production practices by requiring oil well operators to

complete their wells in accordance with a new FERC regulatory scheme. Failure by oil well operators to comply with the FERC regulatory directives results in severe penalties which would not arise under Texas' regulatory framework.

Regulation of oil and gas production is a complex task, best accomplished by state governments through the expertise of their state agencies, staffed to examine in detail all plans for production of hydrocarbons within their boundaries. The Railroad Commission of Texas ("Railroad Commission") is the regulatory agency charged with such responsibility in Texas. The Railroad Commission has historically enacted comprehensive regulatory programs necessary to establish a system ensuring the orderly, nonwasteful and equitable development of natural resources located within the State of Texas. The Railroad Commission's body of regulation involves much more than the superficial interpretation and general application of state statutory law as undertaken by FERC in this case. The Railroad Commission recently completed an exhaustive hearing which addressed a number of problems attendant to the production of hydrocarbons in the Texas Panhandle fields. As this Petition will demonstrate, FERC's misguided attempt to superficially interpret and apply state law and regulatory principles only serves to create conflict and uncertainty within the Texas regulatory arena. States must retain the rights conferred under Section 1(b) of the NGA to regulate production in a full and unfettered manner based on their unique knowledge and study of their state's widely varying geologic conditions and production requirements.

Indeed, this Court has recently reaffirmed the absolute right of the state's to regulate production and gathering of natural gas. *Northwest Central Pipeline Corp. v. State Corp. Comm'n of Kansas*, __ U.S. __, 109

S.Ct. 1262 (1989). In the instant case, this Court should reenforce its earlier pronouncements in *Northwest Central*: "We are not prepared to render meaningless Congress' sweeping saving of power over production to the States . . ." Id. at ____, 109 S.Ct. at 1281. This Court should grant the writ because the judgment of the Tenth Circuit does what this Court refused to do in *Northwest Central*.

STATEMENT OF THE CASE

A. Nature of the Case.

This case arose when FERC issued Opinion No. 239 in *Stowers Oil and Gas Company, et al.*, holding that production and sale of casinghead gas by certain oil well operators in the Texas Panhandle violated the Natural Gas Act and the Natural Gas Policy Act ("NGPA"). FERC denied repeated requests by the State of Texas and the Railroad Commission to limit or defer the scope of the federal proceedings in order to avoid improper and inaccurate federal interpretation and application of unsettled issues of state law and the resulting interference such decisions would necessarily work on the state's regulatory programs.

B. The FERC Administrative Proceeding.

FERC commenced the underlying administrative proceeding on February 15, 1984, by ordering 37 oil well operators in the Panhandle fields to show cause why certain oil and gas production practices, then in use, did not constitute violations of the NGA and the NGPA. The order alleged that quantities of natural gas produced by the oil well operators under authority of Railroad Commission certification was not "casinghead gas," as defined under Texas law, and should have been sold in the interstate market at lower interstate prices.

At the outset of the FERC proceeding, the Attorney General of Texas intervened and urged FERC to limit the scope of its federal inquiry to only those jurisdictional issues affecting the dedication, sale and transportation of natural gas while deferring consideration and adjudication of many underlying, unsettled questions of state law. Noting that the FERC proceeding contemplated resolution of complex and unresolved state law issues, the State asked FERC to defer ruling pending resolution of necessary state law questions by the appropriate state tribunals. The Administrative Law Judge dismissed these requests, and after making her own determinations of the meaning and proper application of Texas law, issued her "Recommended Decision," finding that violations of the NGA and NGPA had occurred and directing that certain production practices in the Panhandle fields be terminated. 30 FERC at ¶ 63,017.

Following issuance of the Recommended Decision, the State and the Railroad Commission again urged FERC to stay its decision so as to avoid interference with ongoing state proceedings addressing the same substantive issues. On July 12, 1985, FERC issued Opinion No. 239, adopting the Recommended Decision "in its entirety, including all findings of fact and conclusions of law." 32 FERC ¶ 61,136. All requests for rehearing of Opinion No. 239 were denied. 33 FERC ¶ 61,207. Petitions for Review were filed. On April 28, 1989, the United States Court of Appeals for the Tenth Circuit upheld FERC's decision in all respects. *Walker Operating Corp. et al. v. FERC*, 874 F.2d 1320 (1989)[1].

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[1]In Opinion No. 239 FERC remanded the Administrative Law Judge's Recommended Decision against J.B. Watkins and Meyer Farms, Inc., two of the original thirty-seven respondent operators for additional evidentiary findings. Upon remand, the

(Footnote continued on next page)

C. *Statement of Facts*

1. *The Panhandle Fields*

The Panhandle Fields encompasses approximately 1.4 million acres across nine Texas counties. The fields are comprised of a series of complex formations known as the Granite Wash, Arkosic Dolomite, Brown Dolomite, and Moore County Lime. Enormous quantities of hydrocarbons are located

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ALJ conducted a second evidentiary hearing addressing limited evidentiary points specifically relating to the two named respondent operators. FERC issued Opinion No. 247 upholding the ALJ's additional evidentiary findings and adopting the findings in Recommended Decision upheld in Opinion No. 239.

Petitioner Railroad Commission sought judicial review of both FERC Opinions 239 and 247. The Tenth Circuit docketed Petitioners appeal of each of these cases separately. Petitioners Petition for Review of FERC Opinion No. 239 was docketed as *Walker Operating Co. et. al. v. FERC,* since reported at 874 F.2d 1320 (10th Cir. 1989). Petitioners Petition for Review of FERC Opinion No. 247 was docketed as *Railroad Commission et. al. v. FERC,* since reported at 874 F.2d 1338 (10th Cir. 1989). In its Opinion issued in *Railroad Commission et. al. v. FERC,* the Tenth Circuit expressly adopted its holding in *Walker Operating* as support for its denial of Petitioner Railroad Commission's Petition for Review of FERC Opinion No. 247. Inasmuch as Petitioner Railroad Commission's grounds for appeal of FERC Opinion No. 247 in *Railroad Commission et. al. v. FERC,* were the same grounds as those urged in *Walker Operating,* and inasmuch as the Tenth Circuit adopted its concurrent holding in *Walker Operating* as support for its denial of Petitioner Railroad Commission's position in *Railroad Commission et. al. v. FERC,* Petitioner Railraod Commission elects not to seek review by this Court of the Tenth Circuit's decision in *Railroad Commission et. al v. FERC.* Petitioner is of the opinion that this Court's review of the Tenth Circuit's decision in *Walker Operating* will be dispositive of all issues raised of interest to Petitioner in both cases.

throughout the fields in both liquid and gaseous phases. 30 FERC at 65,033. Although gas was first discovered in the field in 1918, gas production initially developed only incidentally through the search for oil, there being no large volume market for natural gas until the early 1930's when pipelines were first constructed to midwestern and northern markets. Early oil completion practices resulted in the production of casinghead gas which was vented into the atmosphere or flared for lack of a market.

Prompted by this significant waste of gas in the Panhandle fields and problems in other parts of the state, the Texas Legislature, in May of 1935, enacted a comprehensive oil and gas conservation statute. This statute gave the Railroad Commission broad authority to regulate the production of oil and gas in Texas in order to prevent waste and protect correlative rights.

The Railroad Commission held extensive hearings throughout 1935 to evaluate the development of the Panhandle fields in preparation for passage of comprehensive rules governing production and well completion practices. In these hearings, it became apparent that a unique problem had developed with the recent construction of gas pipelines. The pipeline companies, in order to assure themselves of a supply of gas adequate to justify the tremendous expense attendant to construction of pipelines to Chicago and other distant points, had substantially garnered most natural gas lease rights. These transactions generally severed "dry gas" rights from oil and casinghead gas rights. Because of these severances, the Railroad Commission faced a substantial correlative rights conflict not present in any other area of the state -- a need to ensure that the owners of dry gas rights and oil/casinghead gas rights would compete for separate reserves. Based on the premise that properly completed wells would compete for different and discrete

hydrocarbon deposits, the Railroad Commission established gas fields and oil fields, and provided for the formation of separate surface proration units.

In the early 1980's, certain natural gas operators sought administrative changes in the Panhandle fields well spacing and allowable production rules.[2] Thereafter, the Railroad Commission, recognizing that continued review of production practices in the Panhandle fields was warranted, convened a field-wide hearing to examine the effectiveness of the existing production rules.[3]

2. Federal Regulation

Commencing in 1954, the Federal Power Commission (the predecessor to the FERC), regulated producer sales of natural gas for resale in interstate commerce. "Dry" gas from gas wells in the Panhandle fields had generally been sold in the interstate market pursuant to certificates issued under Section 7 of the NGA. In contrast, casinghead gas produced from different oil fields underlying the same acreage had generally been sold in intrastate commerce. Prior to

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[2]On September 8, 1981, Phillips Petroleum Co. filed an application in Docket No. 10-77,314 to request the Railroad Commission to amend its special field rules applicable to all fields in the Panhandle District.

[3]In July 1985, the Railroad Commission began an investigation into oil and gas production practices in the Panhandle fields which has culminated in more than four months of open hearings, over 10,000 pages of testimony and over 1,000 exhibits. On March 20, 1989, the Railroad Commission issued an Amended Final Order which repealed previous field rule orders and adopted a comprehensive set of comprehensie new rules for the drilling, completion and operation of oil and gas wells in the fields. The Railroad Commission's Amended Final Order appears as Exhibit E in the attached Appendix.

1979, casinghead gas produced from the Panhandle oil fields neither flowed in interstate commerce nor was it subject to federal regulation. 30 FERC at 65,046. Upon its enactment, the NGPA provided that certain incentive prices were exempted from NGA jurisdiction. NGPA §601(a)(1)(B); 15 U.S.C. §3431(a)(1)(B). The determination of whether a well qualified for incentive prices under the NGPA was made the initial responsibility of the states subject to limited FERC review. NGPA §503; 15 U.S.C. §3413. Under NGPA pricing provisions the first oil well in a "new onshore oil proration unit" qualified for Section 103 incentive pricing. NGPA § 103; 15 U.S.C. §3313.

ARGUMENT

A. FERC Opinion No. 239 Exceeds FERC's Authority Under Section l(b) of the Natural Gas Act.

Section l(b) of the NGA reserves exclusive jurisdiction to the states over the "production or gathering" of natural gas. Congress intended that the states should retain such regulatory authority over the production and conservation of hydrocarbons within their boundaries. Section l(b) expressly provides: "The provisions of this chapter . . . shall not apply . . . to the production or gathering of natural gas." 12 U.S.C. §717(b).

Congress' clear recognition of the production of natural gas as an activity which the states had authority to regulate has been acknowledged by this Court. In *FPC v. Panhandle Eastern Pipe Line Co.*, 337 U.S. 498, 509 (1949)(emphasis added), the Court recognized the legislature's intent:

> [t]he legislative history of this Act is replete with evidence of the care taken by Congress to *keep the power over the production and*

> *gathering of gas within the states.* This probably occurred because the state legislatures, in the interest of conservation, had delegated broad and elaborate power to their regulatory bodies over all aspects of producing gas. The Natural Gas Act was designed to supplement state power and to produce a harmonious and comprehensive regulation of the industry. *Neither the states nor [the] federal regulatory body was to encroach upon the jurisdiction of the other.*

In the landmark decision of *Phillips Petroleum Co. v. State of Wisconsin*, 347 U.S. 672 (1954), producer sales of natural gas for resale in interstate commerce were found to be within the FPC's NGA jurisdiction. This Court, however, made clear that the physical activities, facilities and properties used to produce and gather natural gas were not within that jurisdictional conveyance:

> [i]n *FPC v. Panhandle Eastern Pipe Line Co.* . . . we observed that the "natural and clear meaning" of the phrase "production or gathering of natural gas" is that it encompasses "the producing properties and gathering facilities of a natural gas company." Similarly, in *Colorado Interstate Gas Co. v. FPC* we stated that *"[t]ransportation and sale do not include production or gathering,"* and indicated that the *"production or gathering" exemption applies to the physical activities*, facilities, and properties used in the production and gathering of natural gas.

Id. at 678 (emphasis added). Six years later, the Court took the opportunity to highlight the jurisdictional dichotomies drawn in *Phillips*:

> [t]he "production or gathering exemption relates to the physical activities, processes and facilities of production or gathering, but not to sales of the kind affirmatively subjected to Commission jurisdiction. This accommodation of the two relevant clauses of Section 1(b) give context to the national objectives of the Natural Gas Act as expounded in *Phillips*, and to the Commission's jurisdiction to accomplish them, *while in no way interfering with state regulatory power over the physical processes of production or gathering in furtherance of conservation or other legitimate state concerns.*

United Gas Improvement Co. v. Continental Oil Co. (Rayne Field), 381 U.S. 392, 402-03 (1965)(emphasis added).

In *Saturn Oil & Gas Co. v. FPC*, 250 F.2d 61 (10th Cir. 1957), *cert. denied sub nom., Humble Oil & Ref. Co. v. FPC*, 335 U.S. 956 (1958), this Court provided additional clarification to the jurisdictional bifurcation of NGA Section 1(b). *Saturn* involved a determination of the particular point in time at which exempted production and gathering operations ceased and FPC jurisdiction over sales commenced. *Saturn's* sales of natural gas were made at the wellhead, at a point in time after the gas had been brought forth from the earth (i.e. had been "produced") but before the gas had been "gathered." In citing to the seminal case of *Phillips*, the Court held:

> [t]hese cases [citations omitted] and *Colorado Interstate Gas Co. v. FPC* are referred to in the *Phillips* decision as holding that the production or gathering exemption *applies to the physical activities, facilities, and properties* used in the production and gathering of natural gas and not to the business of production and gathering. Until there is a sale of the natural gas produced by such operations and installations in interstate commerce for resale, they are exempt. *In the event of such a sale the jurisdiction of the Commission [FPC] applies but only because of the sale and only to the extent that the Natural Gas Act confers jurisdiction.*

Id. at 68.(emphasis added). Thus, by conditioning federal jurisdiction upon the physical occurrence of the first sale of natural gas, the Court inferentially affirmed that all activities relating to the drilling and extraction of natural gas are exempt from NGA regulation.

Most recently, this Court stated:

> [u]nless clear damage to federal goals would result, FERC's exercise of its authority must accommodate a State's regulation of production.

Northwest Central Pipeline Corp. v. State Corp. Comm'n of Kansas, __ U.S. __, ___ , 109 S. Ct. 1262, 1280 (1989).

While the Railroad Commission acknowledges FERC jurisdiction to determine ultimate federal issues involving dedication and pricing of natural gas, the state must always be allowed to resolve any and all

underlying state law questions relating to production and well completion practices. This scheme recognizes the proper decisional sequence required to administer both state and federal programs and is not a "heavy handed" attempt to threaten "clear damage to federal goals." Principles of federalism and comity dictate as much. *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

This Court's holdings thus ratify the proposition that the production and gathering exemption applies to the *facilities* utilized in producing and gathering gas, such as wellbores, casing, and tubing, as well as to the activities of producing and gathering gas, such as well spacing, drilling, and completion practices.

While FERC has contended in the case below that the production and gathering exemption has been narrowly construed, FERC also acknowledges that "a core of activities remains beyond Commission [FERC] regulation." *Panhandle Eastern Pipe Line Co. v. TXO Prod. Corp.*, 34 FERC ¶ 61,292 at 61,524 (1986). The courts have consistently rejected FERC's attempts to dictate operators' practices in the drilling of wells, workovers, recompletions, or abandonment of wellbores producing natural gas, because this would "encroach on areas reserved to the states." *Shell Oil Co. v. FERC*, 566 F.2d 536, 539-41 (5th Cir. 1978), *aff'd per curiam*, 440 U.S. 192 (1979).

In *Panhandle Eastern*, FERC dismissed a complaint by a producer alleging drainage of dedicated interstate gas reserves caused by the production activities of producers on adjoining non-dedicated leases. Even though the interstate market may have been deprived of a fair share of the natural gas reserves, FERC ruled that it could not remedy the drainage because of the limitations of its jurisdiction over production and gathering activities. *Panhandle*

Eastern, 34 FERC at 61,525. Indeed, FERC recognized that the failure of a state to fully exercise its jurisdiction over production regulation "does not expand this Commission's jurisdiction to reach activities expressly excluded from federal regulatory purview by Section l(b) of the NGA." *Id.*

FERC Opinion No. 239, nevertheless, undertakes to directly regulate many of the practices relating to the production of gas, contrary to Section l(b) of the NGA and this Court's own dictates. Most, if not all of the acts and practices which FERC found to be illegal involve the "drilling and spacing of wells and the like." *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 603 (1945). The illegal acts cited by FERC involved completion techniques, perforation practices, well spacing, well classification, and related matters. The FERC administrative hearings considered evidence and made findings attendant to "the act of bringing forth gas from the earth," which is the essence of the "production or gathering" exemption under Section l(b). *Saturn Oil & Gas Co. v. FPC*, 250 F.2d at 64.

In the case below, FERC relied on the Tenth Circuit's holding in *National Assoc. of Regulatory Utility Commissioners v. FERC*, 823 F.2d 1377 (lOth Cir. 1987)(*"NARUC"*), which addressed FERC's jurisdiction over producing reserves. However, FERC's jurisdiction so conferred under *NARUC* is limited to FERC's consideration of the availability of gas supplies for interstate distribution purposes. Any jurisdiction so conferred must necessarily rely on state determinations of what, and which, underground hydrocarbons make up such reserves. These determinations rest upon the states' regulation of production and well-completion practices.

In light of the foregoing, FERC Opinion No. 239 represents an unprecedented and totally unwarranted

intrusion into state regulation of the production of natural gas and violates Section 1(b) of the NGA. Permitting FERC to determine the manner in which oil wells and gas wells may be drilled and completed would all but eliminate the "production or gathering" exemption and deprive Texas of jurisdiction over the conservation of its natural resources, the prevention of waste, and the economical and efficient development of its mineral resources. Further, Opinion No. 239 is directly contrary to FERC's own contemporansous ruling in *Panhandle Eastern*. The Tenth Circuit judgment upholding FERC Opinion No. 239 must, therefore, be reversed.

B. FERC Improperly Interpreted and Applied Texas Law.

The Panhandle fields vary substantially in producing characteristics. The fields cover an area over 100 miles long and 20 miles wide. The producing formations are sandstones and carbonates which were deposited across a now-buried mountain range which resulted in sediment thicknesses ranging from zero (at mountain peaks) to over a thousand feet (in mountain valleys). The Railroad Commission has exhaustively examined the production practices of the Panhandle fields over the past seven years. This application of local expertise is the heartbeat of the state's jurisdictional program to regulate production and gathering.

The Railroad Commission is charged by Texas law with the duty to prevent waste and protect correlative rights. Tex. Nat. Res. Code Ann., §§ 85.001 *et seq.* and §§ 86.001 *et seq.* (Vernon 1978 & Supp. 1989). The Railroad Commission must be permitted to perform these duties on a case-by-case basis because of the existence of widely varying geologic and operating

parameters in a myriad of producing formations throughout the state.

Despite Congress's explicit denial to FERC of regulatory jurisdiction over production, FERC attempts to "back door" its way into the State's regulatory province by contending that the issues in the case below "involve the interpretation and application of federal statutes." Curiously, however, the "statutes" actually interpreted and applied by FERC to formulate and support its Opinion are Texas statutes governing the production and classification of oil and gas wells in the Panhandle fields. FERC's determination that the parties violated federal law rests exclusively on its interpretation of important questions of state law.

The FERC approach and the Texas approach to regulation of production from the Panhandle fields are not harmonious. In Opinion No. 239, FERC has made a rigid determination that each operator must identify the point of gas-oil contact in his wellbore and that casinghead gas is only that gas produced from below such point. Under FERC's approach a well having a gas-oil ratio exceeding 4146 cubic feet of gas per barrel of oil (4146:1) is improperly completed above the gas-oil contact and is taking gas that does not qualify as casinghead gas. 44 FERC ¶ 61,128 at 61,355 (1985). FERC's arbitrary determination is based on FERC's conclusion that gas-oil ratios above 4146:1 indicate improper production from a dry gas horizon.

Conversely, while the Railroad Commission would urge each operator to determine, if practicable, the point of gas-oil contact, the Railroad Commission necessarily recognizes that a gas-oil contact point cannot always be precisely determined and "where there are both producible oil and free gas horizons, there may be a transition zone of up to 50 feet between the two." Railroad Commission Amended Final Order,

Oil and Gas Docket No. 10-87,017 at 4, 18. Under Railroad Commission rules, an oil well is presumed to be properly completed if it has a gas-oil ratio of up to 5000 cubic feet of gas per barrel of oil (5000:1), unlike the 4165:1 ratio adopted by FERC. The Railroad Commission also will permit perforation of an oil wellbore whenever, "a test of the isolated 50 feet interval below the top of perforations yields enough oil on a stabilized 72 hour test to classify as a statutory oil well," *i.e.* whenever such a test of the wellbore reveals a gas-oil ratio of up to 100,000 cubic feet of gas per barrel of oil (100,000:1). Tex. Nat. Res. Code Ann. §86.002(6)(Vernon 1978). In addition, in determining whether an oil well is properly completed, the Railroad Commission would consider as guidelines perforation depth, location of wells in anomalous areas, competition with surrounding wells, and producing performances. Under Texas law an oil well complying with any one of these guidelines will be presumed to be properly drilled and completed and gas produced from such a well is presumed to qualify as casinghead gas. Thus, FERC's decision to impose an absolute and fixed standard conflicts with the Railroad Commission's determination that regulation solely by reference to a gas-oil contact is impractical. The Railroad Commission has found it necessary to regulate the Panhandle fields by establishing flexible oil well guidelines intended to prevent waste and protect correlative rights.

Not only does FERC Opinion No. 239 conflict with existing Texas law, the conflicts will become more apparent in the future as operators face compliance with two inconsistent regulatory schemes. Operators should not be expected to adhere to inconsistent regulatory systems, regardless of whether the architects of those systems purport to pursue common objectives. At present, an operator in the Panhandle fields may comply with Railroad Commission rules and

yet violate FERC's production constraints, or may comply with FERC's production rules and still breach Railroad Commission regulations. This dilemma will foster unnecessary hardship and confusion. Congress contemplated that operators should look to but one agency for rules governing proper production practices -- the Railroad Commission of Texas.

While FERC Opinion No. 239 purports to apply Texas law and specific Railroad Commission rules, it actually preempts state examination and resolution of important state regulatory issues by misinterpreting and mis-applying Texas law before the same regulatory issues have been finally resolved by the state. Where this Court would preempt state law when state law attempts to intrude into a federally occupied field, this Court should also hold that the federal regulators are barred from transgressing into a field of regulation exclusively reserved to the states by federal law. *Silkwood v. Kerr-McGee Corp.*, 464 U.S. 238 (1984). The Tenth Circuit judgment upholding FERC Opinion No. 239 must, therefore, be reversed.

C. FERC Incorrectly Redefined the Scope of Proration Units and Thereby Unlawfully Circumvented the Exclusive State Jurisdiction to Designate Proration Units.

Many of the oil wells that FERC decided were improperly completed had previously been granted NGPA Section 103 pricing determinations by the Railroad Commission. Section 103 of the NGPA defines a new onshore production well as:

> [A]ny new well . . .
> (3) which is not within a *proration unit*
> (A) which was in existence at the time the surface drilling of such well began;

> (B) which was applicable to the reservoir from which such natural gas is produced; and
>
> (C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

NGPA §103(c); 15 U.S.C. §3313(c) (emphasis added). The NGPA defines "proration unit" to mean:

> (A) any portion of a reservoir, as *designated by the State* or Federal *agency having regulatory jurisdiction with respect to production* from such reservoir, which will effectively and efficiently drained by a single well; [or]
>
> (B) any drilling unit, production unit, or comparable arrangement, *designated* or *recognized by the State* or Federal *agency having jurisdiction with respect* to *production* from the reservoir, to describe that portion of such reservoir which will be effectively and efficiently drained by a single well. . . .

NGPA §2(8); 15 U.S.C. §3301(8) (emphasis added). The Railroad Commission is the jurisdictional agency in Texas to make such determinations. Accordingly, the key test for Section 103(c) well certification is that a well not be drilled in an existing proration unit, *as defined by the Railroad Commission.* Texas law simply provides that a proration unit consists of acreage assigned to a properly completed oil well. 16 Tex. Adm. Code §3.40.

Although the Railroad Commission's well category determinations became final under Section 503 of the NGPA, FERC found that many of the Section 103 wells were within existing proration units. In this regard, FERC ruled that where an oil well and a gas well are drilled on overlapping acreage, FERC can impose its own definition of a proration unit. 30 FERC at 65,048. FERC's definition of proration units under the "gas-oil contact" standard announced in Opinion No. 239, assumes that gas produced from an oil well above the point of "gas-oil" contact must have necessarily been produced from an existing gas well proration unit. Again, FERC's distorted view of its role under the NGPA violates all the clear precepts of federal and state law.

Moreover, FERC improperly exercised its jurisdiction regarding the subject wells because the Railroad Commission already had rendered final and binding well category determinations based on the statutorily-required findings of Section 103. For FERC to rule in its Opinion No. 239 that many of these same wells were completed within an existing proration unit directly contradicts the prior final determinations made by the Railroad Commission. Consequently, FERC's redefinition of proration units constitutes an impermissible exercise of jurisdiction into an area expressly reserved to the states. In addition, the Section 103 pricing determinations were not timely challenged by FERC,[4] and therefore, FERC waived its

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[4]Section 503 of the NGPA establishes the exclusive procedure for making well-category determinations under the NGPA. Section 503(a) provides that the "state agency" (in this case the Railroad Commission) is authorized to make "final" determinations for the purpose of "applying the definition of new, onshore production well under §103(c)." These determinations are then subject to limited review by FERC and once the period for *(Footnote continued on next page)*

right to reverse the prior final state determination. The Tenth Circuit judgment upholding FERC Opinion No. 239 must, therefore, be reversed.

D. FERC Erroneously Failed to Defer to Appropriate State Tribunals.

In the proceedings below, the State repeatedly urged FERC to defer its resolution of issues of federal jurisdiction until such time as appropriate State tribunals were able to fully and finally adjudicate the underlying issues of state law. This Court has acknowledged that federal courts should properly abstain from exercising jurisdiction over matters involving "difficult questions of state law bearing on policy problems of substantial public import . . . ." *Colorado River Water Cons. Dist. v. United States*, 424 U.S. 800, 817, *reh. denied*, 426 U.S. 912 (1976); *Louisiana Power & Light Co. v. City of Thibodaux*, 360 U.S. 25 (1959)

By analogy, FERC should have deferred to the State authorities when presented with the need to apply unresolved state law issues which would substantially impact the Texas regulatory program. This Court's doctrine of absention appropriately applies in the area of deferral when a federal agency seeks to resolve federal issues which impact upon and require resolution and application of state law. *Railroad Commission of Texas v. Pullman Co.*, 312 U.S. 496, 501

(Footnote contimued from previous page)
FERC review is past, the determinations are binding with respect to such natural gas. The determinations may be reopened only pursuant to NGPA Section 503 which requires a hearing on each determination. In this case, the Section 103 determinations granted to the oil well operators became final and binding and FERC never moved to reopen these determinations as required under Section 503(d) of the NGPA. 33 FERC ¶ 61,421 (1985).

(1941); *Burford v. Sun Oil Co.*, 319 U.S. 315 (1943). In this case, the Texas regulatory authorities are the proper entities to interpret the meaning of applicable state law. FERC must respect the distinction between state and federal competence. *New Orleans Pub. Serv., Inc. v. City of New Orleans*, 798 F.2d 858, 860 (5th Cir. 1986). Further, FERC has in past decisions recognized its jurisdictional limitations and deferred in favor of authoritative state action. In *Panhandle Eastern*, FERC announced that it had no jurisdiction to act in the areas of production and gathering. Likewise, FERC refused to exercise its jurisdiction in matters of local contract law:

> [a]s in *Arkla* this issue [contractual intent of the parties] is a matter of local contract law and is beyond the jurisdiction of the Commission. Once the issue of the applicability of the negotiated contract price is decided however, the Commission would have jurisdiction to decide whether the . . . contract as interpreted or reformed by the state court, in fact contains a negotiated contract price.

United Gas Pipeline Co., 27 FERC ¶ 61,196 at 61,366 (1984), *citing*, *Arkansas Louisiana Gas Co.*, 24 FERC ¶ 61,201 (1983).

FERC lacked legal authority to adjudicate the pivotal state law issues in this case. FERC's insistence on unilaterally deciding state law issues in an expedited hearing, while proceedings concerning the same and related issues were pending before Texas state courts and the Railroad Commission, and in the face of the state's repeated request to defer consideration of state law issues, is clearly a violation of the principles of federalism and comity. Further, FERC's unwillingness to consider the state's request to

hear and decide state law matters in joint session with the state's regulatory commission, as authorized under 15 U.S.C. §717(p), is further evidence of FERC's blatant ambivalence toward the state's jurisdictionally delegated authority to regulate "production and gathering." FERC erred by prematurely exercising its jurisdiction without respect for the proper jurisdictional division pronounced in the NGA and NGPA.

CONCLUSION

Review by this Court is necessary to correct the Tenth Circuit's erroneous application of federal law. Section l(b) the NGA reserves to the states the power and authority to regulate "production and gathering," and FERC, in its Opinion No. 239, has impermissibly and erroneously intruded into this area. Additionally, FERC violated the NGPA and unlawfully circumvented the exclusive state jurisdiction to designate proration units. Finally, FERC failed to defer to the express reservation of authority granted the states to make determinations of important state law issues.

Respectfully submitted,

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(2)

89-196

NO. ________

IN THE
SUPREME COURT OF THE UNITED STATES
OCTOBER TERM, 1988

RAILROAD COMMISSION OF TEXAS,
Petitioner

V.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

Appendix To Petition For Writ Of Certiorari To The United States Court Of Appeals For The Tenth Circuit

VOLUME 1

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EXHIBIT A

PUBLISH

UNITED STATES COURT OF APPEALS

TENTH CIRCUIT

WALKER OPERATING CORPORATION, et al., ***Petitioners***

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86-1206
86-1207
86-1208

v.

FEDERAL ENERGY REGULATORY COMMISSION, ***Respomdent***

PHILLIPS PETROLEUM COMPANY; NORTHERN STATES POWER COMPANIES; LAKE SUPERIOR DISTRICT POWER COMPANY; NATURAL GAS PIPELINE COMPANY OF AMERICA; IOWA PUBLIC SERVICE COMPANY; ANADARKO PRODUCTION COMPANY; PAN EASTERN EXPLORATION COMPANY; INTER-CITY GAS; THE ENERGY ISSUES INTERVENTION OFFICE OF THE MINNESOTA DEPARTMENT OF PUBLIC SERVICE; NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.; COLORADO INTERSTATE GAS COMPANY; DORCHESTER MASTER LIMITED PARTNERSHIP; MOBIL PRODUCING TEXAS & NEW MEXICO INC.; WILLIAMS NATURAL GAS COMPANY; TEXACO PRODUCING INC.; CONOCO, INC.,

Intervenors.

Jerry D. Courtney, of Lowe & Courtney, of Clarendon, Texas, for Stowers Oil & Gas Company, and Walker Operating Corporation; Robert J. Kapelke, of Gorsuch, Kirgis, Campbell, Walker & Grover, of Denver, Colorado, with him on the briefs for Walker Operating Corporation; and Miles O'Laughlin, of Pampa, Texas, of counsel, with him on the briefs for Stowers Oil & Gas Company.

Renea Hicks (Jim Mattox, Attorney General of Texas; Mary F. Keller, Executive Assistant Attorney General for Litigation; and Larry J. Laurent, Assistant Attorney General, on the briefs), Special Assistant Attorney General of Texas, Attorney of Record, for the Railroad Commission of Texas.

Edward J. Grenier, Jr., Robert W. Clark, III, and Gail S. Gilman, of Sutherland, Asbill & Brennan, of Washington, D.C., for Cabot Pipeline Corporation.

Joe H. Foy, of Bracewell & Patterson, of Houston, Texas, for J.B. Watkins.

Jody G. Sheets, of Gassaway, Gurley, Sheets & Mitchell, of Borger, Texas, for Lucky Bird Petroleum, Inc.

John H. Conway (Catherine C. Cook, General Counsel, and Jerome M. Feit, Solicitor, with him on the brief), Attorney, for the Federal Energy Regulatory Commission.

James L. Trump (Philip R. Ehrenkranz and Paul F. Forshay, of Squire, Sanders & Dempsey, of Washington, D.C., with him on the brief), of Squire, Sanders & Dempsey, of Washington, D.C., for Dorchester Master Limited Partnership.

John L. Williford and Jennifer A. Cates, of Bartlesville, Oklahoma, for Phillips Petroleum Company.

P. M. Schenkkan, of Vinson & Elkins, of Austin, Texas, for Anadarko Petroleum Corporation and Pan Eastern Exploration Company.

Paul E. Goldstein, Jerome Mrowca, and Barbara A. Gustafson, of Lombard, Illinois, for Natural Gas Pipeline Company of America.

Patrick J. McCarthy, of Adams and McCarthy, of Omaha, Nebraska; Frank J. Duffy, Vice President and General Counsel, and Jane G. Alseth, of Northern Natural Gas Company, Division of Enron Corp., of Omaha, Nebraska; and George J. Meiburger and Steve Stojic, of Gallagher, Boland, Meiburger and Brosnan, of Washington, D.C., for Northern Natural Gas Company, Division of Enron Corp.

Gene R. Sommers, of Northern States Power Company, of Minneapolis, Minnesota, for Northern States Power Companies.

Christopher K. Sandberg, of Attorney General's Office, State of Minnesota, St. Paul, Minnesota, for the Energy Issues Intervention Office of the Minnesota Department of Public Service.

Charles H. Shoneman, of Bracewell & Patterson, of Washington, D.C., and David Lindberg, of Houston, Texas, for Texaco Producing Inc.

Before LOGAN, and TACHA, Circuit Judges, and A. ANDERSON, District Judge.*

TACHA, Circuit Judge.

* Honorable Aldon J. Anderson, Senior United States District Judge for the District of Utah, sitting by designation.

This case presents for review, pursuant to 15 U.S.C. § 717r(b) and 15 U.S.C. § 3416(a)(4), two orders issued by the Federal Energy Regulatory Commission (FERC). These administrative orders determined that certain oil well operators had violated federal law by the diversion of natural gas dedicated to interstate commerce and by selling that gas at a price in excess of the statutorily established maximum price. We hold that FERC had jurisdiction to issue those orders, that FERC's findings of fact were based upon substantial evidence, that its conclusions of law were reasonable, and that there are no procedural grounds for overturning the orders. We affirm.

I.

The Texas Panhandle is the site of a vast hydrocarbon reservoir, the overlying surface area of which is some 124 miles long and averages approximately twenty miles in width. This reservoir contains both oil-producing and gas-producing formations, with the most significant formation for natural gas production being the brown dolomite. Often, a gas producing horizon overlies an oil producing horizon. Furthermore, when a formation produces both gas and oil, the hydrocarbons constituting oil, being denser than those constituting gas, usually will be found in the lower portions of that formation. Within a specific well, the contact line between the gas zone and the oil zone is referred to as the "gas-oil contact."

Within this area, generally referred to as the Panhandle Field, the spacing of oil wells and of gas wells must comply with state regulations that establish specific oil well and gas well proration units. A proration unit here is "[t]he area in a pool that can be efficiently and economically drained by one well, as determined by [the agency regulating production]." H.

Williams & C. Meyers, *Oil and Gas Terms* 777 (7th ed. 1987); *see* 15 U.S.C. § 3301(8). The Railroad Commission of Texas has designated oil fields by county within the Panhandle Field area and has established ten- or twenty-acre oil proration units for the oil wells in these fields. Likewise, the Railroad Commission has divided the Panhandle Field area into two gas fields, establishing 640-acre gas proration units in the Panhandle West Gas Field and 160-acre gas proration units in the Panhandle East Gas Field. Within the Panhandle Field, the gas rights and the oil rights to the same surface area often are separate leasehold estates held by separate parties. Thus, at times, separate and multiple leasehold estates may apply to the various hydrocarbons produced from a single well bore. *See Dorchester Gas Producing Co. v. Harlow Corp.*, 743 S.W.2d 243, 250-51 (Tex. Ct. App. 1987, no writ).

Because a gas proration unit and an oil proration unit can occupy the same surface area, and because of the "split lease" situation, in the Panhandle Field area it is possible ---and quite often--- the case that the proration units for several oil wells might overlap a single gas well's proration unit, with the oil wells being operated by a different operating company from that operating the gas well. As the Fifth Circuit recently noted, "[w]ith the advent of new drilling and legal strategies, the so-called 'split leases' have now for several years produced a steady flow of gas, controversy, and litigation." *Pan E. Exploration Co. v. Hufo Oils*, 855 F.2d 1106, 1109 (5th Cir. 1988).

From its early days the geological and regulatory realities of the Panhandle Field have led periodically to friction between oil producers and gas producers, especially over problems arising from the perforation of oil well casings in a gas-producing horizon above the oil-producing horizon in which the well was completed.

The gas producers saw this activity, sometimes called "high perforation," as resulting in production of natural gas to which they held proper title.

In the Panhandle Field area, production of oil usually will result in some natural gas also being produced from the oil well. This, in fact, occurs in the area that is the subject of these proceedings, because there the "free gas phase overlies and is in contact with a black oil zone." *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,031 (1985) (recommended decision). At a minimum, this type of gas ---from an oil-producing horizon --- and inevitably produced along with the oil from that horizon is known as "casinghead gas." The parties here dispute what else is included in that term.

The statutory and regulatory structure of Texas oil and gas law recognizes the possibility of gas and oil production from the same well. Texas statutes therefore classify specific producing wells as "oil wells" or as "gas wells" based on a specific well's "gas-oil ratio."[1]

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[1]The gas-oil ratio is "[t]he number of cubic feet of gas produced per barrel of oil produced." H. Williams & C. Meyers, *Oil and Gas Terms* 398 (7th ed. 1987).

The Texas statutory definition of gas well provides that:

"Gas well" means a well that:

(A) produces gas not associated or blended with oil at the time of production;

(B) produces more than 100,000 cubic feet of gas to each barrel of oil from the same producing horizon; or

(C) produces gas from a formation or producing horizon productive of gas only encountered in a well bore through which oil also is produced through the inside of another string of casing. Tex. Nat. Res.Code Ann. § 86.002(5) (Vernon 1978). The statutory definition of oil well provides that: "'Oil well' means any well that produces one barrel or more of oil to each 100,000 cubic feet of gas." *Id.* § 86.002(6).

In 1983 the FERC enforcement staff began a preliminary investigation into natural gas sales by oil operators in the Panhandle West Gas Field. The investigation focused on the activities of thirty-seven oil well operators whose oil wells and oil proration units were located on the same surface acreage (the subject acreage) as the gas wells and gas proration units of Dorchester Gas Producing Company (Dorchester). In February 1984 FERC issued an order requiring the thirty-seven oil well operators to show cause why they should not be found to have violated section 7(b) of the Natural Gas Act (NGA), 15 U.S.C. § 717f(b), by the diversion of natural gas dedicated to interstate commerce, and section 504(a)(l) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. § 3414(a)(l), by selling that gas at a price in excess of the statutorily established maximum price. *Stowers Oil & Gas Co.*, 26 FERC ¶ 61,207, 61,478-80 (1984) (show cause order).

A hearing was conducted, and in January 1985 the administrative law judge (ALJ) issued a recommended decision that found thirty-five of the oil well operators in violation of one or both of the statutory provisions. *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017 at 65,048-49 (1985) (recommended decision). The ALJ found that the evidence against the two remaining operators was inconclusive and required further investigation. *Id.* at 65,049.

In determining whether the operators had sold natural gas at a price in excess of its statutory ceiling price, the ALJ first had to determine whether that gas was being produced from reserves that Dorchester had dedicated to interstate commerce. Any gas produced from a Dorchester gas proration unit is dedicated gas. Although the operators' oil proration units and the Dorchester gas proration units sometimes occupy overlapping surface areas, the ALJ concluded that the

Texas regulatory scheme used each well's gas-oil contact to divide the overlying gas proration units from the underlying oil proration units. Therefore, if the operators had produced gas from above the gas-oil contact, they would have been diverting natural gas dedicated to interstate commerce, and, consequently, they would have been selling gas at a higher ceiling price than that allowed by law.

The operators claimed that it was ultimately irrelevant whether gas from their wells had been produced from dedicated reserves. They pointed to pricing category determinations made by Texas for most of their wells. Those determinations, they asserted, removed all gas produced by those wells from the statutory ceiling price for dedicated gas. The ALJ concluded, however, that those well determinations covered only the *casinghead* gas produced by the operators and that, as a practical matter, the Texas definition of casinghead gas covered only that gas produced from below the gas-oil contacts. Therefore, if the operators were producing gas from above the gas-oil contact, they were, in fact, diverting dedicated gas and selling it at a price above its statutory ceiling price.

In July 1985 FERC affirmed the ALJ'S recommended decision "in its entirety, including all findings of fact and conclusions of law." *Stowers Oil & Gas Co.*, 32 FERC ¶ 61,043, at 61,136 (1985) (opinion no. 239). After FERC issued a subsequent order denying motions for stay and requests for rehearing, *Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207 (1985), the thirty-five operators appealed to this court for review of the Commission's orders. Before this court, the petitioners are those operators together with third parties who have also petitioned for review. Other third parties are present as intervenors, some in support of the petitioners and some in support of the respondent, FERC.

II.

This case requires us to examine the appropriate demarcation of authority between federal and state regulatory agencies. Much of the petitioners' argument on appeal is devoted to the contention that FERC impinged impermissibly upon areas reserved for state regulation and, therefore, attacks the agency's jurisdiction below. Congress, moreover, has directed the reviewing courts to "hold unlawful and set aside agency action . . . found to be . . . in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." 5 U.S.C. § 706(2)(C). Therefore, before turning to specific judicial review of FERC's findings of fact, its conclusions of law, or its decision, we address this threshold issue of FERC's jurisdiction.

A.

Congress has established a regulatory scheme that allocates specific areas of natural gas regulation to state or to federal regulators. We first examine, therefore, the contours of that regulatory scheme.

Prior to congressional action, the Supreme Court held that the "mere force of the commerce clause of the Constitution" barred state agencies from interfering with interstate sales of natural gas. *Missouri ex rel. Barrett v. Kansas Natural Gas Co.*, 265 U.S. 298, 307-08 (1924). In 1938 Congress stepped into the area by enacting the NGA, ch. 556, 52 Stat. 821 (1938) (codified as amended at 15 U.S.C. §§ 717-717w). "[W]ithout supplanting any of the existing authority of the state agencies, the Act was intended to provide a powerful regulatory partner, the Federal Power Commission, which could regulate activities where the state bodies could not." *Corporation Comm'n v. Federal Power Comm'n,* 415 U.S. 961, 962 (1974) (Rehnquist, J.,

dissenting from summary affirmation).[2] The NGA delineated specific areas as areas of federal regulation or of state regulation. For example, the transportation or sale of natural gas for resale in interstate commerce was affirmatively placed within the federal regulatory sphere, while intrastate commerce in natural gas, and such matters as production or local distribution, were relegated to the state regulatory sphere.[3] Perhaps the most noteworthy area reserved for state regulation was the "production or gathering of natural gas," 15 U.S.C. § 717(b).

Although Congress delineated areas of federal and of state regulation, inevitably conflicts developed between the two regulatory spheres. Such conflicts, however, are subject to the principle that the jurisdiction of the states is contingent upon state regulation not intruding into those areas clearly within the sphere of federal regulation. In *Northern Natural Gas Co. v. State Corp. Comm'n*, 372 U.S. 84 (1963), the

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[2]The NGA named the Federal Power Commission as the federal agency responsible for the enforcement of the Act. *See* 15 U.S.C. §§ 717a(9), 717l-717o, 717s. In 1977 FERC assumed those enforcement responsibilities. *See* 42 U.S.C. §§ 7172(a), 7341.

[3]Section l(b) of the NGA establishes the state and federal regulatory areas. That section states:

> (b) The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.
>
> 15 U.S.C. § 717(b).

Supreme Court addressed a state's defense of its regulation on the basis of the production or gathering exemption and noted that "it has been consistently held that 'production' and 'gathering' are terms narrowly confined to the physical acts of drawing the gas from the earth and preparing it for the first stages of distribution," *id.* at 90. Furthermore, the Court declared:

> it was settled even before the passage of the Natural Gas Act, that direct regulation of the prices of wholesales of natural gas in interstate commerce is beyond the constitutional power of the States -- whether or not framed to achieve ends, such as conservation, ordinarily within the ambit of state power.

Id. at 90 (emphasis in original). Finally, the Court held that, after the enactment of the NGA, "[t]he federal regulatory scheme leaves no room either for direct state regulation of the prices of interstate wholesales of natural gas or for state regulations which would *indirectly* achieve the same result." Id. at 91 (citation omitted) (emphasis added).[4] The jurisdiction of FERC

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[4]Then-Justice Rehnquist's dissent from summary affirmation, in *Corporation Comm'n v. Federal Power Comm'n*, 415 U.S. 961 (1974), provides a decidedly forceful comment on the practical decline of the states' power under the NGA. The comment is also a poetic one. Noting that "the state regulatory agencies were among [the NGA's] strongest supporters," *id.* at 962 (Rehnquist, J., dissenting), Rehnquist recalls the following limerick:

"There was a young lady from Niger
Who smiled as she rode on a tiger.
They returned from the ride
With the lady inside,
And the smile on the face of the tiger."

(footnote continued on next page)

"was not intended to vary from state to state, depending upon the degree of state regulation and of state opposition to federal control." *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 681 (1954).

Not only must state regulatory action give way if it, directly or indirectly, intrudes into the comprehensive federal regulatory scheme, but it is also true that state regulation under the production or gathering exemption does not bar legitimate federal regulatory action that Congress clearly delegated to FERC. *In Colorado Interstate Gas Co. v. Federal Power Comm'n*, 324 U.S. 581 (1945), the Supreme Court considered an appeal of a federal order fixing new rates for gas transported by two natural gas companies. The Court, addressing the argument that the federal order was barred by the production or gathering exemption, held that the exemption did not preclude the federal agency "from reflecting the production and gathering facilities of a natural gas company in the rate base . . . for the purposes of determining the reasonableness of rates subject to its jurisdiction." Id. at 603. Thus, even though "[t]hat treatment of producing properties and gathering facilities has of course an indirect effect on them," the production and gathering clause did not shield those properties or facilities from the consequences of the proper federal regulatory action. *Id.*

Over its first forty years, the NGA regulatory structure -- with prices in the interstate market controlled by federal regulation and prices in the intrastate markets largely left to market forces -- began to create problems. "[S]hortages in the interstate

(footnote continuned from previous page)
Id. at 961 (Rehnquist, J., dissenting). Justice Rehnquist then states that, given recent case law concerning the NGA, "the state regulatory agencies must surely feel a special kinship with the young lady from Niger." *Id.* at 962 (Rehnquist, J., dissenting).

market developed because gas producers could get higher prices in unregulated intrastate markets." *FERC v. Martin Exploration Management Co.*, 108 S. Ct. 1765, 1767 (1988). In response to this situation, in 1978 Congress enacted the NGPA, Pub. L. No. 95-621, 92 Stat. 3351 (1978) (codified as amended at 15 U.S.C. §§ 3301-3432).[5]

> The statutory scheme established by the NGPA divides natural gas production into numerous categories that are distinguished by the date that production began from a well or the particular type of drilling involved. Gas in these categories can be broadly classified as "old" gas, "new" gas, or difficult to produce gas. "Old" gas is generally that produced from wells that had been operating before the passage of the NGPA. . . ."New" gas is generally that produced from wells that began production after the passage of the NGPA. . . .Several methods of production are specifically described in the statute as difficult to produce gas. . . . The categories are not mutually exclusive: a particular sale may be "dually qualified" within a "new" or "old" gas category and also a difficult to produce category.
>
> The NGPA established ceiling prices for each of these categories of natural gas production.

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[5]The NGPA named FERC as the federal agency responsible for the enforcement of the Act. *See* 15 U.S.C. §§ 3301(24), 3411, 3414(b).

Martin Exploration Management Co. v. FERC, 813 F.2d 1059, 1063-64(10th Cir. 1987) (citations omitted) (footnotes omitted), *rev'd on other grounds*, 108 S. Ct. 1765 (1988).

With the enactment of the NGPA, some doubt arose whether Congress had "altered those characteristics of the federal regulatory scheme which provided the basis in *Northern Natural* for a finding of pre-emption." *Transcontinental Gas Pipe Line Corp. v. State Oil & Gas Bd.*, 474 U.S. 409, 417 (1986). The Supreme Court soon dispelled that doubt and held that Congress' shifting of some specific pricing regulation away from FERC and into the control of market forces had not removed that regulation from the "comprehensive federal regulatory scheme." *Id.* at 422. Consequently, Congress had not "intended to give the States the power it had denied FERC." Id. (reversing judgment of Mississippi Supreme Court that NGPA had vitiated *Northern Natural Gas*). Also, because the NGPA's natural gas categories spanned both interstate and intrastate gas, "the NGPA in some respects expanded federal control, since it granted FERC jurisdiction over the intrastate market for the first time." *Id.* at 421.

In sum, the Supreme Court has narrowly interpreted the exceptions to FERC's jurisdiction over the regulation of natural gas. With this in mind, we turn to FERC's actions in this case to determine whether they impermissibly impinged upon regulatory activities expressly reserved for the state.

B.

"The standard of review on a jurisdictional decision of the FERC is whether the decision was without an adequate basis in law." *Alexander v. FERC*, 609 F.2d 543, 546 (D.C. Cir. 1979), *quoted in National*

Ass'n of Regulatory Utility Comm'rs v. FERC, 823 F.2d 1377, 1382 (10th Cir. 1987). A recent Tenth Circuit decision upheld FERC's determination that it had jurisdiction over whether certain gas was dedicated to interstate commerce. *National Ass'n of Regulatory Utility Comm'rs*, 823 F.2d 1377. In making that decision, this court looked to the statutory language, its interpretation by the Supreme Court, and policy considerations in holding that FERC's interpretation of the congressional intent was reasonable. *Id.* at 1383, 1385.

The petitioners here mount an attack against the statutory jurisdiction of FERC. They contend generally that the production or gathering clause bars FERC from hearing any issues involving such matters as gas-oil ratios, gas-oil contacts, casinghead gas, or high perforations. More specifically, they contend that in this case the integral nature of these "production" issues barred FERC from inquiring into either the scope of Dorchester's natural gas reserves dedicated to interstate commerce or the scope of the Texas pricing determinations covering the petitioners' wells. We disagree.

The Commission here was regulating the price ceilings of sales of natural gas in interstate commerce. As the Supreme Court has noted, "sales in interstate commerce for resale by producers to interstate pipeline companies do not come within the 'production or gathering' exemption." *Phillips Petroleum*, 347 U.S. at 680-81 (stating what *Phillips Petroleum* Court saw as the "ground" of the decision in *Interstate Natural Gas Co. v. Federal Power Comm'n*, 331 U.S. 682 (1947)).

In order to ascertain whether the petitioners had diverted gas dedicated to interstate commerce, FERC had to determine the natural gas reserves that were subject to Dorchester's certificate of public convenience

and necessity. Section 7 of the NGA requires a natural gas company to obtain from the Commission "a certificate of public convenience and necessity" prior to engaging in the sale or transportation of natural gas in interstate commerce for resale. 15 U.S.C. § 717f(c), (e).[6] Moreover, once a natural gas company has obtained a certificate of public convenience and necessity, that gas is "dedicated" to interstate commerce, and that producer cannot abandon its supplying of natural gas into interstate commerce, unless the Commission grants it permission to do so, *see United Gas Pipe Line Co. v. McCombs*, 442 U.S. 529, 536, 542 (1979); 15 U.S.C. § 717f(b),[7] or unless that gas falls within the provisions of section 601(a)(1)(B) of the NGPA, *see* 15 U.S.C. § 3431(a)(1)(B).

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[6]Section 2 of the NGA defines a "[n]atural-gas company" as "a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale." 15 U.S.C. § 717a(6).

[7]Section 717f(b) of title 15 of the United States Code states:

> (b) No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

15 U.S.C. § 717f(b).

In 1954 Dorchester acquired Panhandle Field gas reserves[8] and applied for a certificate of public convenience and necessity, which the federal regulatory agency issued on February 6, 1956.[9] That certificate covers the Dorchester gas wells located on gas proration units that overlap the oil proration units of the petitioners. "The initiation of interstate service pursuant to [a] certificate dedicate[s] all fields subject to that certificate." *California v. Southland Royalty Co.*, 436 U.S. 519, 525 (1978). The Dorchester gas, then, was "natural gas committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the Natural Gas Act was in effect on such date for the first sale of such gas," 15 U.S.C. § 3314(a). *See generally Dorchester Gas Producing Co. v. FERC*, 571 F.2d 823, 825 (5th Cir.

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[8]As the Fifth Circuit stated in reference to this same date and transaction:

> At the time of the acquisition, Dorchester Gas Producing Company did not exist. The acquiring party was Dorchester Corporation, and Dorchester Gas Producing Company was formed to hold the gas reserves in question here sometime after their acquisition. For the purposes of this case, there is no functional difference between Dorchester Corporation and Dorchester Gas Producing Company, and we shall use the name "Dorchester" throughout . . . in order to avoid confusion.

Dorchester Gas Producing Co. v. FERC, 571 F.2d 823, 825 n.1 (5th Cir. 1978).

[9]The certificate was based on a 1952 gas purchase contract executed by Dorchester's predecessor in interest in its leasehold estate. *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,046 (1985)(recommended decision). On June 7, 1954, when the federal agency began regulating interstate gas sales for resale by independent producers, the sales under the 1952 contract had triggered automatically the dedication of the gas reserves under part of the subject acreage. *Id.* at 65,033, 65,034.

1978); 15 U.S.C. §§ 717c-717d (granting federal agency jurisdiction under NGA to set "just and reasonable" rates; providing for agency hearings to establish rates). As such, it was subject to the ceiling price established by section 104 of the NGPA. 15 U.S.C. § 3314; *see also* 18 C.F.R. §§ 154.1-.310 (1988) (federal regulations establishing and regulating rate schedules and tariffs for natural gas); *id.* §§ 271.101(a), 271.401-403 (1988) (establishing price for NGPA § 104 gas).

The ALJ established that Dorchester's certificate of public convenience and necessity applied to --- and therefore dedicated to interstate commerce --- all natural gas from the subject acreage that was not casinghead gas.[10] *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,046 (1985) (recommended decision). In reaching that conclusion, the ALJ considered the geological characteristics of the Dorchester acreage, the application of Texas state law to that acreage, and a 1952 gas purchase contract that preceded the Dorchester certificate. *Id.* The ALJ examined these matters only as a necessary background to applying the relevant federal statutes to these parties. Such an examination was therefore within FERC's jurisdiction.

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[10] Again, we examine at this point only whether the ALJ -- and, consequently, FERC through its subsequent affirmation --- had statutory jurisdiction to delve into matters claimed by the petitioners to be shielded from any federal involvement. We shall take up below an examination into whether FERC's conclusions of law were, in fact, reasonable.

Because the petitioners[11] contended that the Texas pricing determinations for their wells have removed all gas produced by those wells from the dedicated gas ceiling price, FERC had to determine the scope of those pricing determinations. Section 103 of the NGPA establishes a ceiling price for "natural gas" statutorily determined "to be produced from any new, onshore production well." 15 U.S.C. § 3313(a).[12] The statutory determination is to be made by the "Federal or State agency having regulatory jurisdiction with respect to the production of natural gas." 15 U.S.C. § 3413(c)(l); *see also id.* § 3413(a)(l)(C). For the subject

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[11]As we have noted, the petitioners in this case are the oil well operators found by FERC to have violated federal law, together with some third parties that side with those operators. For the sake of convenience, we refer here to "the petitioners' wells" as meaning those wells operated by the original thirty-five operators that FERC found to have violated federal law.

[12]Section 103(c) of the NGPA states:

> For purposes of this section, the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)--
> (1) the surface drilling of which began on or after February 19, 1977;
> (2) which satisfies applicable Federal or State well-spacing requirements, if any; and
> (3) which is not with a proration unit--
> (A) which was in existence at the time the surface drilling of such well began;
> (B) which was applicable to the reservoir from which such natural gas is produced; and
> (C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

15 U.S.C. § 3313(c).

acreage, that agency is the Railroad Commission of Texas (RCT). *See* 18 C.F.R. § 274.501 (1988).

When the proceedings below began, most of the petitioners' oil wells had received section 103 determinations from the RCT.[13] The ALJ approached these determinations as administratively final, *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,030 (1985) (recommended decision), and did not attempt to make new section 103 determinations, *id.* at 65,047; *see also* 15 U.S.C. § 3413(b); 18 C.F.R. § 275.202 (1988). Instead, the ALJ undertook to ascertain the scope of the section 103 determinations consistent with the federal statutory language, *see, e.g.*, 15 U.S.C. § 3313(c)(3) (barring "new, onshore production well" from being within certain pre-existing proration units). The ALJ concluded that the determinations covered "only casinghead gas." *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,030 (1985) (recommended decision). In order to arrive at that conclusion, she examined Texas state law provisions involving such matters as proration units and casinghead gas. *Id.* Again, as was the case with the ALJ's examination of the Dorchester certificate of public convenience and necessity, this examination was undertaken only as a necessary background to the application of the relevant federal statutes.

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[13]Of the 196 oil wells the petitioners operated on the subject acreage, all but 10 were collecting § 103 prices for their gas. *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,030 (1985) (recommended_decision). The remaining 10 wells were collecting # 109 prices for their gas. *Id.* "Section 109 allows ceiling prices for new natural gas that does not fit into a designated category." *Id.* Although § 109, unlike § 103, does not require an agency determination under the NGPA for the producing well, see 15 U.S.C. § 3413(a)(l), it would still, of course, be a violation of federal law to sell what is legally § 104 gas, and is not § 109 gas, at a higher price reserved for § 109 gas.

We hold that FERC's jurisdictional decisions in these proceedings had an adequate basis in law.

C.

The petitioners contend that, even if FERC had jurisdiction to examine state law issues, it should have abstained from doing so. They assert that FERC should have deferred to Texas authorities on these issues, citing primarily to the principles of *Burford*-type abstention.

Burford-type abstention is deference by a federal court in order to avoid needlessly interfering in state activities. *See Burford v. Sun Oil Co.*, 319 U.S. 315, 317-18, 327 (1943). *See generally* 17A C. Wright, A. Miller & E. Cooper, *Federal Practice and Procedure* § 4244 (2d ed. 1988). For several reasons, however, the principles of that abstention should not control this case. First, the procedural posture here is markedly different from the one that caused concern in *Burford*. *Burford* involved a federal court's review, under diversity and federal question (due process) jurisdiction, of an RCT order concerning oil well spacing. Burford, 319 U.S. at 316-17. The federal court's review, moreover, would have preceded any review of the order by the state courts designated to review such orders under Texas law. *Id.* at 325-28. Finally, there was no federal statute or regulation at issue in that case.

By contrast, the proceedings before FERC involved a federal regulatory agency operating in the area of its expertise. The federal agency was clearly acting within its jurisdiction, and it was taking Texas statutes and regulatory determinations at their face value. A *federal* regulatory issue was the issue before

FERC. This is not *Burford*, and FERC was not required to have deferred.[14]

III.

We turn next to our review of the federal agency's findings of fact and of its decisions.

A.

The NGA and NGPA explicitly provide the scope of our review for the findings of fact, stating in identical language that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 15 U.S.C. § 717r(b) (section 19(b) of the NGA); *id.* § 3416(a)(4) (section 506(a)(4) of the NGPA). Here, the Administrative Procedure Act provides an identical standard. *See* 5 U.S.C. § 706(2)(E).

"[Substantial evidence] means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Richardson v. Perales*, 402 U.S. 389, 401 (1971) (quoting *Consolidated Edison Co. v.. NLRB*, 305 U.S. 197, 229 (1938)). That is, "it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury." *NLRB v. Columbian Enameling &*

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[14]In actuality, FERC did stay its proceedings in order to give the RCT time to decide certain state law issues. *Stowers Oil & Gas Co.*, 32 FERC ¶ 61,043, at 61,134-36 (1985) (opinion no. 239). FERC deferred action on *Stowers* until the RCT had completed action in a different proceeding before it and had voted to issue a memorandum to operators in the Panhandle West Gas Field. *Id.* at 61,136. FERC concluded that the RCT memorandum supported the conclusions reached by the ALJ. *Id.*

Stamping Co., 306 U.S. 292, 300 (1939).[15] It is, therefore, "something less than the weight of the evidence," and an agency's finding may meet the standard in spite of "the possibility of drawing two inconsistent conclusions from the evidence." *Consolo v. Federal Maritime Comm'n*, 383 U.S. 607, 620 (1966). This standard "frees the reviewing courts of the time-consuming and difficult task of weighing the evidence, it gives proper respect to the expertise of the administrative tribunal and it helps promote the uniform application of the statute." *Id.*

FERC made findings of fact concerning the geological characteristics of the subject acreage and of the Panhandle Field generally, the events that prefaced the parties obtaining their various leasehold interests and Dorchester obtaining its certificate of public convenience and necessity, and the geological and production realities of the various producing wells on the subject acreage. The petitioners contend that some of these findings are not supported by substantial evidence.

Specifically, the petitioners attack the evidentiary sufficiency for the ALJ's finding that they were producing gas from above the gas-oil contact, see *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,048 (1985) (recommended decision). This finding formed a basis for FERC's conclusion that the petitioners were producing dedicated gas from a Dorchester proration unit. The ALJ stated that her basis for that finding was "the totally persuasive evidentiary presentation of

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[15]The Court, in citing these same cases, has stated that "[a]lthough these two cases were decided before the enactment of the Administrative Procedure Act, they are considered authoritative in defining the words 'substantial evidence' as used in the Act." *Consolo v. Federal Maritime Comm'n*, 383 U.S. 607, 620 n.18 (1966).

the expert witnesses sponsored by [FERC's] Enforcement Staff and Dorchester." *Id.* The ALJ, furthermore, declared that the presentation's "conclusions, based on accepted scientific principles of geology, chemistry, and reservoir engineering, leave no doubt that most of the gas produced by most of the [petitioners] is not casinghead gas . . . and that most of the [petitioners] are producing gas which would otherwise be produced by Dorchester." *Id.* We find that the ALJ relied on the extensive evidence and arguments presented by the various parties in reaching her recommended decision. *See id.* at 65,033-43; *id.* app. C at 65,051-65.

The petitioners also object to the ALJ's use of "secondary evidence" to ascertain the gas-oil contact in specific wells. Furthermore, they cite expert testimony that they contend contradicts the expert testimony relied upon by the ALJ. In the final analysis, however, the petitioners' arguments point at best to the presence of some conflicts in the evidentiary record. In the light of our scope of review, that is simply not enough. After a review of the record as a whole, we conclude that the findings of fact are supported by substantial evidence.

B.

The ALJ concluded that the petitioners were producing dedicated gas from Dorchester's reserves and selling that gas at a price above the price ceiling dictated by section 104 of the NGPA. In so concluding, the ALJ examined Texas state law matters involving proration units, contract language, and the definition of casinghead gas. The definition of casinghead gas played a significant role in the ALJ's analysis, for she concluded that the reserves covered by Dorchester's certificate of public convenience and necessity did not include casinghead gas and that the scope of the petitioners' section 103 well determinations was

limited to casinghead gas. Therefore, once casinghead gas was defined, it was possible to ascertain whether the petitioners had produced gas dedicated under Dorchester's certificate or within the scope of their own well determinations.

1.

We have concluded that FERC had jurisdiction to examine these state law matters. We have concluded also that FERC need not have deferred to the state agencies or state courts. The petitioners, however, expend considerable energy contending that FERC's interpretation of Texas state law, even if within its jurisdiction, is without foundation.

"Unlike factual findings, questions of law are freely reviewable by the courts, and courts are under no obligation to defer to the agency's legal conclusions." *Pennzoil Co. v. FERC*, 789 F.2d 1128, 1135 (5th Cir. 1986). That scope of review is unchanged, of course, when the agency's conclusions of law are based upon relevant state law rather than federal law. *See Wolf v. Gardner*, 386 F.2d 295, 296 (6th Cir. 1967) (court of appeals not required to accept cabinet secretary's conclusions of law based in part on state family law); *Baber v. Schweiker*, 539 F. Supp. 993, 995 (D.D.C. 1982) (mem.) ("substantial evidence" deference "does not attach to an agency's interpretation of state law").

Nevertheless, even if not compelling, legal interpretations on a matter by administrative bodies having expertise in the area are "helpful" to reviewing courts, *Erickson Air Crane Co. v. United States*, 731 F.2d 810, 814 (Fed. Cir. 1984), and "the courts are to give some deference to the Commission's informed judgment" on such legal issues, *FTC v. Indiana Fed'n of Dentists*, 476 U.S. 447, 454 (1986). Generally, then, when a court reviews an agency's careful and studied

conclusions of law pertaining to a matter clearly within the agency's expertise, the court will affirm those conclusions if they are reasonable, *cf. Chapman v. United States, Dept. of Health & Human Servs.*, 821 F.2d 523, 527 (10th Cir. 1987) (agency's interpretation of statute entrusted to its administration limited to whether construction is "reasonable"), although an agency's order may not stand if the agency has misconceived the law," *SEC v. Chenery Corp.*, 318 U.S. 80, 94 (1943).

2.

The petitioners contend primarily that FERC erred in its conclusion concerning the definition of casinghead gas under Texas state law. The petitioners take the position that all gas produced from an oil well is casinghead gas. For the petitioners, then, the crucial distinction is the state statutory classification of wells into "oil wells" or "gas wells." For this position, "any well that produces one barrel or more of oil to each 100,000 cubic feet of gas," Tex. Nat. Res. Code Ann. § 86.002(6) (Vernon 1978), is an oil well, and any gas produced from that well is casinghead gas.

The Texas statutory definition of "casinghead gas" is "any gas or vapor indigenous to an oil stratum and produced from the stratum with oil," *id.* § 86.002(10). Although on its face this definition is consistent with FERC's position, the petitioners argue that their position is the correct interpretation of the legislative intent behind the statute. They point emphatically to a 1940 opinion of the Attorney General of the State of Texas, Tex. Att'y Gen. Op. No. 0-1760 (1940), which concludes that "the term 'casinghead gas' applies to all gas produced from any 'oil well' as defined in [the Texas statutes]," *id.* at 4. The petitioners contend that Texas law has consistently followed this definition, as illustrated by RCT documents and by

such Texas court decisions as *Read v. Britain*, 422 S.W.2d 902 (Tex. 1967).

FERC contends that the Texas state law definition of casinghead gas is that found upon the face of the statute. In addition, FERC points to the fact that the RCT regulations -- presumably meant to clarify any interpretative problems found in the statute's plain language -- virtually repeat the statutory language. The RCT regulations define casinghead gas as "[a]ny gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil." Tex. Admin. Code tit. 16, § 3.69 (1986) (RCT; Oil and Gas Div.; definitions). Finally, the ALJ also noted the administrative hearing had shown "this definition [to be] supported by persuasive expert scientific and engineering testimony." *Stowers Oil & Gas Co.*, 30 FERC 63,017, at 65,046 (1985) (recommended decision).

In determining whether gas was "produced from the stratum with oil," the ALJ referred to the gas-oil contact point. *Id.* at 65,048. The ALJ determined that "Dorchester's proration unit is that portion of the reservoir *above* the gas-oil contact which lies beneath each 640-acre unit assigned to a Dorchester well." *Id.* (emphasis added). The ALJ concluded that gas production coming from above the gas-oil contact is not casinghead gas and, therefore, is gas dedicated to interstate commerce. *Id.*

In examining whether it was reasonable for FERC to have adopted its position, we note that although the authority for that position may not be unopposed, it is certainly well represented in Texas law. In addition to the statutory and regulatory language already quoted, there is virtually overwhelming support for FERC's definitional position in Texas judicial opinions handed down after FERC

issued its orders. *See Amarillo Oil Co. v. Energy-Agri Prods., Inc.*, No. C-6649, 32 Tex. Sup. Ct. J. ____ , ____ (Mar. 8, 1989; slip op. at 12) (holding that "the statutory definition of casinghead gas is not ambiguous"); *Dorchester Gas Producing Co. v. Harlow Corp.*, 743 S.W.2d at 250-51, 258 (upholding instruction charging jury that "the classification of a well by the Texas Railroad Commission does not determine whether gas produced from a well is casinghead gas"). The Texas statutes and regulations, moreover, as a whole are consistent and harmonious with FERC's position. *See, e.g.*, Tex. Nat. Res. Code Ann. §§ 86.093, 86.097 (Vernon 1978); Tex. Admin.Code tit. 16, §§ 3.10(a), 3.13(a)(l), 3.13(b)(4)(B), 3.69 (1986); RCT, *Special Rules Governing the Panhandle District*, II, at rules 1-3 (drilling rules).

FERC's position finds further support in a recent order of the RCT establishing and clarifying regulations designed in part to prevent improper production of gas, by oil well operators, from horizons that produce only gas. *See Final Order Adopting and Clarifying Rules and Regulations for the Panhandle Fields*, RCT, Oil & Gas Docket No. 10-87,017 (Jan. 11, 1989).[16] The RCT adopted verbatim the Texas statutory definition of casinghead gas. *Id.* at 7. Also, the RCT found that "[o]perators can generally use information" from several sources "in an attempt to determine the gas-oil contact in an individual oil well; but the contact cannot always be determined, and can vary substantially across the field." *Id.* at 4.

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[16]The RCT order is not final for administrative purposes until: (1) no motion for rehearing is filed within the period allowed for such motions; (2) the agency has ruled on submitted motions for rehearing; or (3) any submitted motions for rehearing have been overruled by operation of law. Tex. Rev. Civ. Stat. Ann. art. 6252-13(a), § 16(c), (e) (Vernon Supp. 1989).

The fact that the-gas-oil contact point cannot always be precisely determined apparently led the RCT to state that "regulation of the field is best implemented. without reference to an absolute gas-oil contact level," *id.* at 13. The petitioners contend that this language precludes FERC from using the gas-oil contact to determine whether gas being produced was dedicated gas. We disagree. The RCT order merely states a preference, for practical reasons, for regulation constructed without referencing a gas-oil contact. In fact, "[t]he [RCT] has zoned the Panhandle Field reservoir(s) into separate gas fields and oil fields" and "[RCT] field rules require that an oil well be perforated only in levels, sands or strata productive of oil." *Id.* at 5. This example of the RCT's continued recognition of separate producing horizons is consistent with the concept of a gas-oil contact. We hold that it was reasonable in this case for FERC to have used a gas-oil contact in determining whether dedicated gas was being sold.

We find overwhelming support for the reasonableness of FERC's definitional position. Not only is that position supported by the sources we have noted, but many of the sources cited by the petitioners are inconclusive or ambiguous. *Cf. Dorchester Producing Co. v. Harlow Corp.*, 743 S.W.2d at 250-51 (addressing statement found in *Read v. Britain*, 422 S.W.2d 902,-903 (Tex. 1967), concerning casinghead gas). For example, the 1940 Attorney General's opinion states that "[t]he statutory classifications of 'sour gas' and 'casinghead gas' are not absolutely clear," Tex. Att'y Gen. Op. No. 0-1760, at 2, but reasons that the legislature intended "to restrict the term 'casinghead gas' to gas which is produced with oil from an 'oil well,'" *id.* at 3. The opinion also states, however, that "the Legislature evidently considered that where gas is produced as a *necessary incident* to the production of oil

from an oil well, the value of the oil produced would warrant the use of the casinghead gas 'for any beneficial purpose.'" *Id.* at 4 (emphasis added). Such statements, together with the opinion's definition of casinghead gas as "gas produced with oil from an oil well," *id.* at 3, demonstrate the ambiguity of the opinion as it was cited by the parties before FERC. Furthermore, after FERC had concluded its proceedings, the Texas Supreme Court explicitly disapproved the opinion, on the grounds that it failed to follow the plain meaning of the statutory definition of casinghead gas. *See Amarillo Oil*, 32 Tex. Sup. Ct. J. at _____ (slip op. at 12).

Upon review, we find that FERC's conclusions of state law, including the Texas state law definition of casinghead gas, are reasonable.

C.

The petitioners also contend that FERC erred in its conclusion that casinghead gas was the only natural gas covered by the section 103 well determinations for the petitioners' oil wells.

1.

RCT made those well determinations pursuant to sections 503(a)(l)(C)[17] and 503(c)(1)[18] of the NGPA.

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[17]Section 503(a)(l)(C) of the NGPA provides:

(a) General rule.--
(1) Determination.--If any State or Federal agency makes any final determination which it is authorized to make under subsection (c) of this section for purposes of--

. . . .

(C) applying the definition of new, onshore production well under section 3313(c) of this title;

. . . .

(footnotes continued on next page)

As such, they determined that the petitioners' applicable wells were "new, onshore production wells" within the meaning of section 103 of the NGPA and that, consequently, natural gas produced under section 103 from those wells was subject to the ceiling price set by the NGPA for such gas. *See* 15 U.S.C. § 3313. The petitioners contend that all natural gas subsequently produced by those wells is removed from FERC's jurisdiction by section 601(a)(l)(B)(iii) of the NGPA. That section provides that the jurisdiction of FERC under the NGA

> shall not apply solely by reason of any first sale of natural gas which is committed or

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(*footnotes continued from previous page*)

> such determination shall be applicable under this chapter for such purposes unless such determination is reversed under the provisions of subsection (b) of this section or unless such State or Federal agency has waived its authority under the provisions of subsection (c) of this section.

15 U.S.C. § 3413(a)(l)(C). Subsection (b) of the section provides for FERC review of the initial determination. *Id.* § 3413(b). The RCT is the jurisdictional "State or Federal agency" for section 103 determinations applicable to the petitioners' Panhandle Field wells. *See* 18 C.F.R. § 274.501(a)(2) (1988).

[18]Section 503(c)(l) of the NGPA provides:

> (c) State authority.--
> (1) General rule.--A Federal or State agency having regulatory jurisdiction with respect to the production of natural gas is authorized to make determinations referred to in subsection (a) of this section.

15 U.S.C. § 3413(c)(l). The RCT is the "Federal or State agency" that has regulatory jurisdiction over the production of natural-gas by the petitioners' Panhandle Field wells. *See* 18 C.F.R. § 274.501(a)(2) (1988).

> dedicated to interstate commerce as of November 8, 1978, and which is--
>
> . . . .
>
> (iii) natural gas produced from any new, onshore production well (as defined in section 3313(c) of this title).

Id. § 3431(a)(l)(B)(iii) ("section 3313(c) of this title" is § 103(c) of the NGPA).

FERC affirmed the ALJ's conclusion that the section 103 well determinations did not remove any dedicated gas from FERC's NGA jurisdiction. Although the petitioners at times characterize that conclusion as an erroneous interpretation of state law, in fact section 103 determinations have their legal significance as part of the *federal* regulatory structure of the NGPA. The ALJ approached the section 103 determinations as valid and administratively final. The ALJ simply applied the principles and provisions of the NGPA to the well determinations.

FERC arrived at its conclusion by examining the statutory requirements of a section 103 determination and applying those requirements to RCT's determination affecting the petitioners' wells. Section 103 of the NGPA establishes the ceiling price for natural gas produced by a new, onshore production well," 15 U.S.C. § 3313(a),(b), and section 103(c) states that, for the purposes of section 103

> the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)--
>
> (1) the surface drilling of which began on or after February 19, 1977;

(2) which satisfies applicable Federal or State well-spacing requirements, if any; and

(3) which is not within a proration unit--

(A) which was in existence at the time the surface drilling of such well began;

(B) which was applicable to the reservoir from which such natural gas is produced; and

(C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

Id. § 3313(c). The statute therefore provides that a section 103 well cannot be located within a preexistent proration unit[19] which applies to the same reservoir[20]

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[19]The NGPA defines the term "proration unit" to mean

(A) any portion of a reservoir, as designated by the State or Federal agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well;

(B) any drilling unit, production unit, or comparable arrangement, designated or recognized by the State or Federal agency having jurisdiction with respect to production from the reservoir, to describe that portion of such reservoir which will be effectively and efficiently drained by a single well; or

(footnotes continued on next page)

from which the section 103 well produces its natural gas, and which applies to a well that produced natural gas in commercial quantities (or at least that was begun before February 19, 1977, and sometime later became capable of producing natural gas in such quantities).

The Dorchester gas proration units in the Panhandle Field predated the petitioners' section 103 wells and were producing natural gas. Furthermore, if the petitioners' wells were producing gas from within a Dorchester proration unit, they would be "within a proration unit . . . which was applicable to the reservoir from which [the petitioners'] natural gas is produced." *Id.* § 3313(c)(3). The petitioners' section 103 wells,

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(footnotes continued from previous page)

> (C) if such portion of a reservoir, unit, or comparable arrangement is not specifically provided for by State law or by any action of any State or Federal agency having regulatory jurisdiction with respect to production from such reservoir, any voluntary unit agreement or other comparable arrangement applied, under local custom or practice within the locale in which such reservoir is situated, for the purpose of describing the portion of a reservoir which may be effectively and efficiently drained by a single well.

15 U.S.C. § 3301(8)

[20]The NGPA defines the term "reservoir" to mean any producible natural accumulation of natural gas, crude oil, or both, confined--

> (A) by impermeable rock or water barriers and characterized by a single natural pressure system; or
>
> (B) by lithologic or structural barriers which prevent pressure communication.

15 U.S.C. § 3301(6).

therefore, could not be within a Dorchester proration unit, although the surface areas of the Dorchester gas proration units and of the petitioners' oil proration units overlap. By following that analysis, the ALJ concluded that the petitioners' section 103 determinations were applicable only to natural gas produced by the petitioners' oil wells from below the gas-oil contact. *Stowers Oil & Gas Co.*, 30 FERC ¶ 63,017, at 65,047 (1985) (recommended decision). The RCT had declared that its section 103 determinations for the petitioners' wells were made in compliance with all applicable statutory requirements. In reaching her conclusion, the ALJ took the RCT at its word and considered the statutory requirements to have been met.

2.

The petitioners contend that the section 103 well determinations cover all natural gas produced by their wells, even if those wells are deemed to be within a previously existing Dorchester gas proration unit. The petitioners arrive at this conclusion by pointing to the statutory language defining "proration unit" under the NGPA. That definition ties a proration unit to the part of a reservoir that will be "effectively and efficiently drained by a single well." 15 U.S.C. § 3301(8). The federal regulations provide, furthermore, that the jurisdictional agency may make a finding that a well, the drilling of which is begun on or after February 19, 1977,[21] is needed "to effectively and efficiently drain" a portion of an already existing proration unit. 18 C.F.R. § 271.305(b)(l). Section 103 pricing categories may apply to natural gas produced by a well that is covered by such a finding. *Id.* §§ 271.301, 271.305(b)(1). Here,

[21]The NGPA requires that for all # 103 wells the "surface drilling" must have begun "on or after February 19, 1977." 15 U.S.C. § 3313(c)(l).

that agency, the RCT, stated that the petitioners' section 103 determinations met all the applicable statutory requirements. The petitioners argue, therefore, that the RCT made an implicit finding that the petitioners' wells were needed in order to drain existing Dorchester proration units effectively and efficiently. We disagree.

The petitioners section 103 wells were oil wells. It is unreasonable to interpret a section 103 determination for an *oil* well as implicitly making a finding concerning the drainage of a Dorchester *gas* proration unit. Further, the federal regulations clearly state that

> the jurisdictional agency must *explicitly* find that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. This explicit finding must be based on appropriate geological and engineering data and such data must be included in the notice of determination submitted to the Commission.

Id. § 271.305(b)(l) (emphasis added); see *Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,421 n.36 (1985)

(order denying stay and rehearing).[22] Here, no such explicit finding was made.

As FERC noted in its order denying motions for stay and requests for rehearing, "[i]t is clear from the legislative history that the section 103 price was not intended to apply to gas that could be produced by an existing well." *Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,421 (1985). Senator Pearson stated, during floor debate on the NGPA, that section 103 prices were meant to apply only to "natural gas sold from new reservoirs and new extensions of reservoirs." 123 Cong. Rec. 30,373 (1977), *quoted in Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,421 (1985) (order denying stay and rehearing). "The economic incentives . . . should only be applicable to truly new gas discoveries." *Id., quoted in Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,421 (1985) (order denying stay and rehearing).

Section 103 operates to prevent the petitioners from obtaining a section 103 price for natural gas produced from an existing Dorchester proration unit. The petitioners are entitled to a section 103 price for gas produced by their section 103 oil wells only when that gas is produced from their oil proration units and is therefore casinghead gas, that is gas "indigenous to an oil stratum and produced from the stratum with oil." Tex. Nat. Res. Code Ann. § 86.002(10). Such gas

[22]An exception to this procedure did exist for "*second* wells in a proration unit [the drilling of which was begun] after February 19, 1977, and before January 1, 1979, or for which a drilling permit was issued before January 1, 1979." *Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,421 n.36 (1985) (order denying stay and rehearing). That exception was required because of a transitional period during which the regulations implementing the NGPA were not yet in place. *Id.* None of the petitioners' wells met the requirements of the transitional rules. *Id.*

will be from below the gas oil contact and will not be part of Dorchester's dedicated reserves. We affirm the conclusions of law utilized by FERC in reaching its decision.

D.

In addition to a review of the agency's findings of fact and conclusions of law, judicial review of agency action also entails an examination of the agency's reasoning process. The Supreme Court has declared that "the generally applicable standards of [5 U.S.C.] § 706 require the reviewing court" to determine that the agency's "actual choice" was not "arbitrary [and] capricious." *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 415-16 (1971); *accord Bowman Transo., Inc. v. Arkansas-Best Freight Sys.*, 419 U.S. 281, 284 (1974) (noting that "though an agency's finding may be supported by substantial evidence . . . it may nonetheless reflect arbitrary and capricious action"); *Pennzoil Co. v. FERC*, 789 F.2d at 1139 n.31 (citing 5 U.S.C. § 706(2)(A) for "arbitrary and capricious" standard in reviewing "agency decision"). The Court has stated that:

> The scope of review under the "arbitary and capricious" standard is narrow and a court is not to substitute its judgment for that of the agency. Nevertheless, the agency must examine the relevant data and articulate a satisfactory explanation for its action including a "rational connection between the facts found and the choice made." *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168, 83 S.Ct. 239, 245-246, 9 L.Ed.2d 207 (1962). In reviewing that explanation, we must "consider whether the decision was based on a consideration of the relevant factors and

> whether there has been a clear error of judgment."

Motor Vehicle Mfrs. Ass'n of the United States, Inc. v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983) (quoting Citizens to Preserve Overton Park, 401 U.S. at 416).

Applying this standard to FERC's orders, we find an extensive examination of "the relevant data" and a clearly articulated "rational connection" between the agency's findings and its final decision. We affirm FERC's orders upon review.

IV.

Finally, we address a procedural issue raised by the petitioners. On February 15, 1984, FERC issued its show cause order against those petitioners that operated oil wells on the subject acreage. *Stowers Oil & Gas Co.*, 26 FERC ¶ 61,207 (1984). The petitioners contend that the show cause order did not give them adequate notice of the theory under which FERC would proceed. According to the petitioners, the order "was premised on the existence of two separate and identifiable producing formations in the West Panhandle Field": a "dry gas" producing zone coterminous with the brown dolomite formation, and an "oil stratum" from which "casinghead gas" was produced. The petitioners assert that FERC continued under this theory up to the point of its offering rebuttal evidence before the ALJ. At that point, they argue, the enforcement staff presented a new theory of the case: one based upon a state law division of the Panhandle Field along a horizontal gas-oil contact, with gas proration units located above the gas-oil contact and oil proration units located below it.

The petitioners' contention overstates the case. The show cause order properly stated that it "neither makes findings of fact nor reaches conclusions of law with regard to the [petitioners'] alleged acts and practices." *Id.* at 61,480. The order, furthermore, asserted that "[t]he brown dolomite stratum is productive only of dry gas *at the level* at which the operators of each of the oil wells . . . have perforated or have caused the perforation of such oil wells." *Id.* at 61,478 (emphasis added). In its order denying the motions for stay and the requests for rehearing, FERC declared that "the show cause order set the inquiry broadly enough to encompass the concept of the gas-oil contact." *Stowers Oil & Gas Co.*, 33 FERC ¶ 61,207, at 61,423 (1985). We agree.

V.

FERC had jurisdiction to consider those matters examined by it in the adjudicatory hearing. FERC's findings of fact are based on substantial evidence, and its conclusions of law are reasonable. We find no procedural grounds for overturning the orders. FERC's orders are therefore AFFIRMED.

EXHIBIT B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 239

Stowers Oil & Gas Company, *et. al.*

Docket No. GP84-23-000

OPINION AND ORDER

Issued: July 12, 1985

UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION

Stowers Oil & Gas Company, *et al.*

Docket No. GP84-23-000

OPINION NO. 239

APPEARANCES

Thomas K. Anson and *P. M. Schenkkan* for Anadarko Production Company and Pan Eastern Exploration Company.

Robert W. Clark, III, *Maston C. Courtney* and *D. Patrick Lono* for Cabot Pipeline Corporation.

William M. Lange and *Nancy A. White* for Colorado Interstate Gas Company.

Thomas H. Burton for Conoco, Inc.

Norman A. Flaningam and *Karol Lyn Newman* for Consolidated Royalty Owners, Inc.

Philip R. Ehrenkranz, *R. David Kitchen* and *James L. Trump* for Dorchester Gas Producing Company.

Paul W. Fox and *Charles H. Shoneman* for Getty Oil Company.

Jody G. Sheets for Lucky Bird Petroleum.

Michael H. Loftin and *R. A. Wilson* for Meyers Farms, Inc.

J. Paul Douglas for Mobil Producing Texas and New Mexico, Inc.

Joseph Wells for Natural Gas Pipeline Company of America.

Patrick J. McCarthy and *Steve Stojic* for Northern Natural Gas Company.

Jennifer A. Cates and *Joe Cochran* for Phillips Petroleum Company and Phillips Oil Company.

Larry J. Laurent, W. Scott McCollough, Jim Mattox, and *David R. Richards* for the State of Texas.

Jerry D. Courtney, Ivan D. Hafley, Charles A. Moore, Robert W. Perdue, Daniel G. Shillito, and *Michael K. Swan* for Stowers Oil & Gas Company, et al.

Joe H. Foy and *Gail S. Gilman* for J. B. Watkins.

Nathan Fishkin, Robert Fleishman, Michael T. Mishkin and *Steven Ross* for the Federal Energy Regulatory Commission's Enforcement Staff

**UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY
COMMISSION**

Before Commissioners: Raymond J. O'Connor, Chairman; Georgiana Sheldon, A. G. Sousa, Oliver G. Richard III and Charles G. Stalon.

Stowers Oil & Gas Company, *et al.*

Docket No. GP84-23-000

OPINION NO. 239

OPINION AND ORDER

(Issued July 12, 1985)

I. INTRODUCTION

In 1983, the Enforcement staff of the Federal Energy Regulatory Commission (Commission) began an inquiry into natural gas sales by Stowers Oil & Gas Company and thirty-six other oil well operators (respondents) in the Texas Panhandle West Gas Field. It was alleged that respondents have been producing gas from reserves belonging to Dorchester Gas Producing Company (Dorchester) which were committed or dedicated to interstate commerce and selling the gas, in most instances, in intrastate commerce at prices in excess of the maximum lawful price under section 104 of the Natural Gas Policy Act of 1978 (NGPA).[1] The matter was set for an expedited hearing before Judge Brenda Murray, and the respondents were ordered to show cause why they

[1] 15 U.S.C. §§ 3301-3432 (1982).

should not be found in violation of section 7(b) of the Natural Gas Act (NGA)[2] for the alleged diversion of dedicated reserves, and of section 504(a)(l) of the NGPA for the alleged overcharges.[3]

After extensive discovery, a hearing was conducted in July and August of 1984. On January 16, 1985, the presiding judge issued a Recommended Decision finding that all but two of the respondents were violating either section 7(b) of the NGA or section 504(a)(l) of the NGPA, or both,[4] and recommended that they be ordered immediately to cease the unlawful diversion and overcharging. In reaching her decision the judge found that under Texas law casinghead gas cannot be produced above the gas oil contact and therefore production through high perforations in an oil well was gas production. The judge also recommended further investigation of the activities of two of the respondents, Meyer Farms, Inc., and J.B. Watkins.

The Commission in this order affirms the presiding judge's Recommended Decision holding that the respondents have violated either section 7(b) of the NGA or section 504(a)(l) of the NGPA, or both, and orders that they immediately cease the unlawful diversion and overcharging. Further, the Commission sets forth the procedures to be followed for continued investigation of Meyer Farms, Inc. and J.B. Watkins.

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[2]15 U.S.C. §§ 717-717w (1982).

[3]26 FERC ¶ 61,207 (1984).

[4]30 FERC ¶ 63,017 (1985).

II. PROCEDURAL ISSUES/DISPOSITION OF MOTIONS

Certain motions have been filed, either as part of the briefs on exceptions[5] or separately, which require

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[5]On February 8 and 15, 1985, the Commission issued orders allowing the submission of exceptions to the Recommended Decision, (30 FERC ¶¶ 61,125 and 61,150.) As of February 25, 1985, timely briefs on exceptions were filed by: Stowers Oil & Gas Company, *et al.*; Cabot Pipeline Corporation; Consolidated Royalty Owners; Dorchester Gas Producing Company; Lucky Bird Petroleum, Inc.; Getty Oil Company; State of Louisiana Interstate Oil Compact Commission; J.B. Watkins and Tadlock Production, *et al.*, brief *Amicus Curiae*. Tadlock Production, *et al.*'s *Amicus* brief is accepted for filing, but the Tadlock *Amici* are not parties to this proceeding. *See* Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214 (1984). On March 5, 1985, staff filed an answer in opposition to the motion of the Tadlock *Amici* for leave to file their brief.

On February 25, 1985, the State of Louisiana and the Interstate Oil Compact Commission (IOCC) and on March 6, 1985, the Oklahoma Corporation Commission (OCC) filed their briefs on exceptions late. On March 6, 1985, Dorchester and on March 7, 1985, Phillips Petroleum Company (Phillips) filed their answers in opposition to Tadlock's *Amici* motion and to the untimely motions of Louisiana and the IOCC to intervene. On March 12, 1985, Dorchester filed an answer in opposition to the untimely motion of the OCC for leave to intervene. Finally, on March 13, 1985, Phillips filed an answer in opposition to the OCC's motion for late intervention.

For good cause shown, the late interventions will be granted. Accordingly, Phillips' motion for late intervention is granted, and its answer in opposition to the late intervention of OCC is denied. The late motions to intervene of Northwestern Public Service Company, and the Illinois Power Company, are granted.

Finally, the *Stowers* group, Lucky Bird Petroleum, Inc. and J.B. Watkins requested dismissal from these proceedings. Those requests are denied.

disposition. All briefs on exceptions were considered by the Commission in reaching a decision.

On February 25, 1985, Stowers Oil & Gas Company, *et al.* filed a motion requesting oral argument. That motion is denied.

On February 25, 1985, staff moved that the Railroad Commission of Texas (RRC) Examiners' Proposal for Decision in Docket No. 10-77,314, *Application of Phillips Petroleum Company to Amend Rules for Various Fields in the Panhandle District*, (Phillips) be received in the record as a public document item by reference under Rule 508(c).[6] On May 21, 1985, staff moved that the Final Order in the *Phillips* proceeding, issued by the RRC on May 13, 1985, be received in evidence. We find the RRC Examiners' Proposal, which was issued February 1, 1985, and the RRC's Final Order, issued May 13, 1985, to be public documents admissible as items by reference under Rule 508(c).[7] On June 18, 1985, Cabot Pipeline Corporation filed a motion requesting that the transcript of the June 17, 1985, RRC meeting be added to the *Stowers* record. In addition, to complete the record in *Stowers*, we will add the transcripts of the June 10 and July 8 RRC meetings and copies of the July 8 memorandum and letter approved by the RRC. Since the Examiner's Proposal, the RRC's Final Order,

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[6]18 C.F.R. § 385.508(c) (1984).

[7]On March 4, 1985, Northern Natural Gas Company filed an answer in support of staff's motion. On March 11, 1985, the State of Texas filed in opposition to make clear that the RRC Examiner's Proposal is not Texas law until adopted by the RRC. Upon consideration, we find it sufficiently related to this proceeding since it was adopted by the RRC's "Final Order" of May 13, 1985 and is necessary to complete this record. The RRC denied rehearing in *Phillips* on June 17, 1985.

and the RRC transcripts address issues that were the subject of several admitted exhibits, and since they concern the same subject matter as testimony already certified by the judge, staff's and Cabot's motions are granted.[8]

III. RELATED RAILROAD COMMISSION OF TEXAS ACTIONS

On March 12, 1985, the RRC requested this Commission to stay its consideration of Judge Murray's Recommended Decision in order to give the RCC time to decide certain issues of state law, which the RRC assured us were common to both the *Stowers* case and to the *Phillips* case, then pending before the RRC. In response to the RRC's request, we issued a Notice postponing consideration of the Recommended Decision in *Stowers*, granting the parties fifteen days to respond to the RRC's request, and requesting the RRC to advise us regarding the status of the *Phillips* matter within forty-five days.[9]

On May 13, 1985, the RRC issued its Final Order adopting with slight modification the RRC Examiners' Recommended Proposal for Decision in the *Phillips* case. In response, on May 22, 1985, we issued an Order Setting Issues for Oral Argument, granting the RRC

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[8] In addition, staff (and Dorchester) moved that a document previously offered but not yet ruled upon be entered into the record. This document, a motion to vacate a judgment in the *Dorchester v. Harlow* state court action, was tendered on January 14, 1985. The judge did admit as Exhibit 620 the *Harlow* Court's order vacating judgment, but not the motion to vacate, which shows the grounds on which vacation was sought. Since the vacation order was admitted, the "Joint Motion to Vacate" should also be admitted. Accordingly, staff's and Dorchester's request is granted.

[9] 30 FERC ¶ 61,317 (March 12, 1985).

party status and requesting the RRC and other parties to explain:

> (1) how the [R]RC decision in *Phillips* resolves state law issues present in *Stowers* 7/ as the [R]RC has asserted in its petition for stay; and (2) whether it is still necessary to entertain the stay or whether, in light of *Phillips*, the petition for stay is now moot.
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> ---
>
> 7/ For example, such issues include the propriety of what have been called "high perforations" and the definition of "oil" and "casinghead" gas.

On May 31, 1985, the RRC filed a notice (A) declining to become a party to [the *Stowers*] proceeding and, (B) advising us of possible further proceedings at the State level. The RRC further indicated that "the propriety of 'high perforations' and the definition of casinghead gas . . . as it turns out were [issues] not reached in the *Phillips* case." The RRC added that these issues would be addressed at its June 3, 1985 meeting.

While these issues were addressed at the RRC's meeting on June 3, 1985, the RRC postponed further consideration until June 10, 1985.

Subsequently, on June 6, 1985, we issued an Order Clarifying Oral Argument Procedures, confirming the RRC's party status and urging its participation in the oral argument which we had scheduled for June 14 to consider the RRC's renewed request for stay in *Stowers*.

On June 10, 1985, the RRC voted to ensure compliance with certain of its Panhandle Field Rules[10] governing casinghead gas production and high perforations. Specifically, the RRC voted to issue notices to operators in the Panhandle West Gas Field which would have stated:

> Completing an oil well or working an oil well over so that any portion of the producing interval is above the gas-oil contact is not consistent with Special Orders Nos. 10-316 and 10-3087.

Additionally, the notices which the RRC initially approved on June 10 would have stated:

> If a well in the Panhandle Fields was spudded on acreage already assigned to either an oil well or a gas well in a Panhandle Field and the producing intervals of the two wells overlap, the well cannot qualify under Section 103 unless the Commission makes a finding that the later well is necessary to effectively and efficiently drain the portion of the reservoir covered by the pre-existing proration unit.

On June 11, 1985, in a letter to this Commission, the RRC's Special Counsel clarified the RRC's actions

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[10]Rule No. 3 of Oil and Gas Circular 16-B; Special Order No. 10-316; and Special Order No. 10-3087. *See, e.g.*, "Memorandum from the Railroad Commission to All Operators in the Panhandle Fields; Subject: Oil & Gas Well Completions in the Panhandle Fields," dated June 6, 1985. These rules require that the dry "lime gas" formation be cemented off from other formations; that no gas or oil well be permitted to produce gas "from different levels, sands or strata at the same time through the same string of casing;" and that the gas-oil ratio "be kept as low as possible."

taken in the *Phillips* proceedings and on the state law issues regarding high perforations and casinghead gas, stating:

> In recognition that it did not reach certain issues raised in the Phillips case (for example, the high perforations and definition of casinghead gas issues) ... [t]he RRC considered those issues outside the context of a contested case on June 3, and, following lengthy discussion, postponed action on those issues until June 10 . . . . Yesterday, the RRC took action with respect to the matters which it considered on June 3 which action culminated in the issuance of the attached two notices.

However, no notices were attached to the RRC Special Counsel's letter. Observing that the RRC's action essentially resolved the state law issues related to *Stowers*, on June 12, 1985, we cancelled oral argument in the *Stowers* case recognizing that the RRC's petition for stay was moot in light of its action on June 10.

At its next meeting on June 17, 1985, the RRC reviewed its previous decision to issue notices to operators interpreting Panhandle Field Rules in Panhandle West Gas Field and rescinded its decision of June 10, 1985, to issue the notices, never having issued the notices to the operators. Although the decision to issue the notices to the operators was rescinded on June 17, the statement by the RRC on high perforations and casinghead gas which was included in the notices was totally consistent with the Commission's Recommended Decision in *Stowers*.

After deciding that it needed additional time to resolve the high perforations and casinghead gas issues, the RRC postponed consideration of the matter

until its meeting on June 24, 1985. However, the matter was not discussed either at the June 24 meeting, or at the July 1, 1985 RRC meeting.

On July 8, 1985, the RRC voted to issue a memorandum to the operators in the Panhandle West Gas Field which enunciates the applicable field rules, statewide rules and statutes and requires the operators to file updated information on their oil and gas wells.[11] Specifically, the memorandum states:

> Completing an oil well or working over an oil well so that any portion of the producing interval is above the gas-oil contact may not be consistent with the above-cited orders, rules and statutes. Likewise, completing a gas well or working over a gas well so that any portion of the producing interval is below the gas-oil contact may not be consistent with the above-cited orders, rules and statutes.

The July 8 memorandum is similar to the June 10 unissued notices, except that any presumption of violation by the operators in the Texas Panhandle West Gas Field has been removed from the text of the July 8 memorandum.

In addition to deciding to issue the memorandum, on July 8 the RRC also voted to issue a letter to the operators in the Panhandle West Gas Field setting forth the qualifications necessary to be

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[11]The memorandum cites Rule No. 3 of Oil and Gas Circular 16-B; Special Order No. 10-316, dated May 4, 1938; Special Order No. 10-3087, effective December 1, 1941; Statewide Rules 10 and 13; and Texas Natural Resources Code § 86.012 and § 86.097.

classified as a gas well under section 103 of the NGPA. The letter states:

> . . . a well cannot be spudded within an existing proration unit applicable to the reservoir from which the subject well is producing gas. If a well in the Panhandle Fields was spudded on acreage already assigned to either an oil well or a gas well in a Panhandle Field and the producing intervals of the two wells overlap, the well cannot qualify under Section 103 unless the Commission makes a finding that the later well is necessary to effectively and efficiently drain the portion of the reservoir covered by the pre-existing proration unit. The Commission will not consider making such a finding for any well which is not in compliance with all applicable rules and regulations, including those regarding proper perforations and completions.

At the RRC's request, we deferred action on *Stowers* for several months to allow the RRC sufficient time to act on these state law issues. The position taken by the RRC in voting to issue the memorandum and letter to the operators in the Panhandle West Gas Field, along with the RRC's legal analysis, discussions and statements fully support this Commission's Recommended Decision. Furthermore, the Recommended Decision finds that the Texas statutes and field rules are unambiguous and consistent with the purposes of the NGA and NGPA.[12]

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[12]For further general confirmation that there is a meaningful distinction under Texas law between casinghead gas that is necessarily produced with oil and other gas *see* Colorado Interstate Gas Company v. Hufo Oils, Lynn S. Hunt and Carl C. Foulds, No. M0-84-CA-58 (W.D. Tex. June 20, 1985).

IV. J.B. WATKINS AND MEYER FARMS

We find that evidence of NGA or NGPA violations is inconclusive as to J.B. Watkins and Meyer Farms. Consequently, the Commission directs staff, utilizing an expert if necessary, to gather data and conduct a recombined fluid sample analysis or any other test(s) necessary on the wells in question to determine whether J.B. Watkins and Meyer Farms are in violation of the Natural Gas Act and/or the Natural Gas Policy Act. Within forty-five days of the issuance of this order, the results of staff's additional tests will be presented to the presiding judge in the form of prepared direct testimony. At the same time, respondents J.B. Watkins and Meyer Farms may present any prepared testimony of their own. The presiding judge, within two weeks following the filing or the prepared testimony, will allow cross-examination of any witness(es) resulting from the filing of prepared testimony. Based upon the additional record compiled in this matter, the presiding judge will file with the Commission appropriate recommendations with respect to J.B. Watkins and Meyer Farms within seventy-five days of the issuance of this order.

V. CONCLUSION

The Commission finds after careful review and due consideration of the recommended decision and the findings of fact and conclusions of law contained therein, as well as all briefs, motions and other documents entered into the record subsequent to the Recommended Decision, that the respondents in the Panhandle West Gas Field are in violation of section 7(b) of the NGA for the diversion of dedicated reserves and section 504(a)(l) of the NGPA for the over charges. Therefore, we affirm the *Stowers* Recommended Decision in its entirety, including all findings of fact and conclusions of law.

The Commission orders:

(A) All respondents, (except J.B. Watkins and Meyer Farms, Inc.) shall immediately cease and desist from selling natural gas from their wells on the acreage subject to this proceeding in the Panhandle West Gas Field in violation of section 7(b) of the Natural Gas Act and section 504(a) of the Natural Gas Policy Act as set forth in the Recommended Decision issued January 16, 1985.

(B) Enforcement staff is authorized to take all necessary action to accomplish the cessation of the NGA and NGPA violations.

(C) The procedure is set forth in the body of this Opinion and Order to determine the possible violations of the NGA and/or NGPA by Meyer Farms and J.B. Watkins.

(D) J.B. Watkins and Meyer Farms must allow access to the subject wells for the purpose of gathering data and conducting a recombined fluid sample analysis or any other test(s) necessary on the subject wells to determine if a violation of the NGA and/or NGPA has occurred.

(E) The proceeding is remanded to the presiding judge to set a procedural schedule to consider appropriate remedies.

By the Commission. Commissioner Richard's separate statement is attached.

(SEAL)

Kenneth F. Plumb,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Stowers Oil & Gas Company, *et al.*

Docket No. GP84-23-000

(Issued July 12, 1985)

Separate Statement of Commissioner Richard:

I agree with the decision but want to make clear that on the state law controversy my agreement is based on the discussion of the Texas Railroad Commission's (TRC) actions on page 7-9.

It is also my understanding from our staff that the TRC has not asked us to defer our consideration of this case until they obtain and analyze more information nor has it claimed that the factual findings by us would intrude on their jurisdiction. Since I am departing the Commission, if later a request is lodged, my fellow Commissioners may wish to entertain the TRC's views on the subject in this important area of the historic jurisdictional role.[1]

As I have earlier stated:

[T]he real concern should be the federal government's understanding and proper respect for the

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[1]This Commission in this case has surely shown this concern.

states' historic and future autonomy, with the goal being active cooperation rather than confrontation.[2]

Oliver G. Richard III
Commissioner

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[2]Richard, *Appeal from Jarndyce v. Jarndyce: The State Role Under the Natural Gas Policy Act of 1978*, 41 La. L. Rev. 147, 172, (1980).

EXHIBIT C

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Raymond J. O'Connor, Chairman;
A. G. Sousa and
Charles G. Stalon.

Stowers Oil & Gas Company, *et al.*

Docket Nos. GP84-23-000,
and GP84-23-012 through -021

ORDER DENYING MOTIONS FOR STAY AND REQUESTS FOR REHEARING

(Issued November 13, 1985)

I. INTRODUCTION

On July 12, 1985, the Federal Energy Regulatory Commission (Commission) issued Opinion No. 239[1] in the Stowers Oil & Gas Company, *et al.* (Stowers) proceeding. That opinion and order adopted the administrative law judge's Recommended Decision[2] issued on January 16, 1985, which ordered thirty-five respondents to cease and desist from selling natural gas in violation of section 7(b) of the Natural Gas Act (NGA)[3] and/or section 504(a) of the Natural Gas Policy Act (NGPA).[4] Opinion No. 239 also ordered further investigation of two other respondents to determine

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[1]32 FERC ¶ 61,043 (1985)

[2]30 FERC ¶ 63,017 (1985).

[3]15 U.S.C. § 717f(b) (1982).

[4]15 U.S.C. § 3414(a) (1982).

whether there are possible violations of the NGA and/or NGPA, and directed the presiding judge to begin the remedy phase.

On July 29, 1985, Stowers filed a motion for stay of Opinion No. 239 with an accompanying memorandum, and on August 9, 1985, respondent Lucky Bird Petroleum (Lucky Bird) filed a supplemental motion for stay incorporating Stowers' motion and memorandum. In addition, Lucky Bird stated that unless a stay is granted it will be unable to comply with certain well testing orders of the Railroad Commission of Texas (RRC) because the gas produced during a test could neither be sold under Opinion No. 239 nor flared under state regulations. Timely answers in opposition to these motions for stay were filed.[5]

On August 9 and August 12, 1985, timely applications for rehearing of Opinion No. 239 were filed.[6] On August 26, 1985, Dorchester filed an answer in opposition to the supplemental motion for stay of

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[5]Phillips Petroleum Company (Phillips), Natural Gas Pipeline Company of America (Natural), the Enforcement Staff of the Commission (Staff), Northern Natural Gas Company a Division of Internorth, Inc. (Northern), and Dorchester Gas Producing Company (Dorchester) filed timely answers.

[6]Cabot Pipeline Corporation (Cabot), Getty Oil Company (Getty) (Texaco Producing Inc. advised the Commission on August 16, 1985, that it had succeeded to the interest of Getty herein), J.B. Watkins, Lucky Bird, the State of Texas (Texas), Stowers, Consolidated Royalty Owners, Inc. (CRO), Walker Operating Corporation (Walker Corp.), Prairie Oil Company, et al. (Prairie Group), and the RRC filed timely applications for rehearing. The RRC accompanied its request for rehearing with a motion seeking leave to intervene out-of-time in order to file its rehearing request. The RRC has already been granted intervenor-party status in this proceeding, as was made clear by our "Order Clarifying Oral Argument Procedures," issued June 6, 1985. 31 FERC ¶ 61,293 (1985)

Lucky Bird and to the motion to intervene of the RRC. On August 28, 1985, the Commission issued a "tolling" order for the sole purpose of further consideration.

Herein the Commission addresses the merits of the issues raised in both the motions for stay and the requests for rehearing, and denies both the motions for stay and the requests for rehearing for the reasons discussed below.

II. DISCUSSION

A. *Motions for Stay*

Lucky Bird's motion for stay stresses an interpretation of Opinion No. 239 which Lucky Bird argues would preclude testing the subject wells under the RRC's *Phillips* order of May 13, 1985.[7]

1. *Well Testing*

We believe it is important to answer the question as to whether or not testing is allowed at the outset, before addressing the motions for stay. Opinion No. 239 does not preclude any testing required by the RRC in *Phillips*. In fact, Opinion No. 239 does not require respondents to cease *all* gas production from their wells. It does require respondents to cease all gas production which is in violation of the NGA or the NGPA.

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[7]RRC Docket No. 10-77,314, *Application of Phillips Petroleum Company to Amend Rules for Various Fields in the Panhandle District (Phillips)*. The Stowers' Stay Memorandum makes the same argument at 20-22.

Under the *Phillips* order,[8] oil wells that are attached to low temperature extraction (LTX) units must be retested to determine whether they are correctly classified as oil wells, or are improperly maintaining an oil well classification by utilizing liquefied natural gas. Opinion No. 239 does not preclude such state ordered tests. Opinion No. 239 simply orders all respondents, (except J.B. Watkins and Meyer Farms, Inc.) to immediately cease "from selling natural gas from their wells on the acreage subject to this proceeding in the Panhandle West Gas Field in violation of section 7(b) of the Natural Gas Act and [/or] [9]section 504(a) of the Natural Gas Policy Act as set forth in the Recommended Decision issued January 16, 1985."[10] Clearly, only those sales in violation of federal law need to cease; but proper testing for state purposes is encouraged by this Commission and is in no way inconsistent with Opinion No. 239.[11]

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[8]We note that a Travis County, Texas, state court has remanded *Phillips* to the RRC on a procedural issue. However, the court affirmed the substance of the RRC decision and the testing procedures thereunder. Accordingly, the remand is in no way an impediment to our determinations in *Stowers*.

[9]Since some respondents sell their gas in interstate commerce only, the dual conjunctive "and/or" would have been more precise than "and".

[10]Opinion No. 239, 32 FERC ¶ 61,043 at 61,137 (1985).

[11]Objections that the precise volumes that are lawful and unlawful must be delineated specifically by the Commission are groundless. Each operator is able to apply the law to his particular production to determine what gas sales and pricing violates the federal statutes and what does not. This Commission does not consider any production required to comply with reasonable RRC testing requirements to be violative of the federal statutes or of Opinion No. 239, even if the operator has not yet sealed off the dry gas zones. Only the sales diverted from interstate commerce or at
(Footnote continued on next page)

2. *Criteria for Stay*

Stowers argues that a stay is warranted under the four-prong criteria of *Virginia Petroleum Jobbers Association v. FPC*.[12] These criteria are: (1) the likelihood that the party seeking the stay will prevail on the merits; (2) whether irreparable harm will result if a stay is not granted; (3) whether other parties will be harmed if a stay is granted; and (4) how the general public interest will be affected by a stay. We find these criteria have not been met. Therefore, we deny the requests for stay.

(a) *Likelihood of Prevailing on the Merits*

Stowers claims it is likely to prevail on the merits. Citing *Washington Metropolitan Area Transit Commission v. Holiday Tours, Inc.*,[13] Stowers asserts that "the original requirement of 'likelihood of success on the merits' has been considerably relaxed, so that now only a 'substantial case' must be shown."[14] Stowers repeats five basic arguments made even more extensively in its Request for Rehearing to try to demonstrate it has a "substantial case." Specifically, Stowers argues that Opinion No. 239 (1) turns on an incorrect interpretation of state law, (2) intrudes on states' rights, (3) is an *ex post facto* determination of an NGPA gas category, (4) is not supported by any

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prices in excess of the maximum lawful price have been found to be violative.

[12]259 F.2d 921 (D.C. Cir. 1958). *See* Memorandum in Support of Motion for Stay of Commission Order [sic] No. 239, [Stay Memorandum], filed by Stowers on July 29, 1985, at 3 ff.

[13]559 F.2d 841 (D.C. Cir. 1977).

[14]Stay Memorandum at 3.

evidence, and (5) was issued in a manner that violated due process rights.[15]

Briefly, Opinion No. 239 is based on our interpretation of the NGA and NGPA, federal statutes which are the Commission's sole responsibility to enforce. Not only is Opinion No. 239 consistent with state law, but differing interpretations of local rules "must yield to the interpretation compelled by the policies and legislative goals of the federal statute."[16] Neither the Recommended Decision nor Opinion No. 239 suggest that any *ex post facto* action was taken with regard to the well determinations at issue. Rather, Opinion No. 239 delineates what gas is encompassed by the respective determinations. Extensive and persuasive record evidence supports Opinion No. 239, which adopts the findings of fact, conclusions of law, and application of the facts to law of the Recommended Decision.[17] Finally, sequential notational voting[18] in no way violates the Government in the Sunshine Act, and any assertions of procedural improprieties based on "change of theory" are equally groundless.[19]

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[15]*Id.* at 8-16.

[16]Ecee, Inc. v. FERC, 645 F.2d 339, 356 (5th Cir. 1981).

[17]*See, e.g.*, the arguments in the record and the analysis in Appendix C of the Recommended Decision, which the judge and this Commission found persuasive and convincing. 30 FERC ¶ 63,017 (1985).

[18]*See* Communications Systems, Inc. v. FCC, 595 F.2d 797 (D.C. Cir. 1978).

[19]These arguments are addressed in detail in the section discussing requests for rehearing.

(b) *Asserted Irreparable Harm to Movants*

Stowers asserts that it will experience irreparable harm because "the Commission's order imposes a severe distortion of business and cash flow on the members of the Producer Group,"[20] and if shut-in, the wells may be physically damaged and conservation and competition diminished.

It is not at all clear that the spectre of bankruptcy raised by Stowers even if realistic, is due to the effect of Opinion No. 239, as Stowers claims. Clearly, purchasers have been making payments into escrow accounts for some time *prior* to issuance of Opinion No. 239.[21] Moreover, any money damages that do derive from the opinion and order are insufficient to constitute "irreparable harm," because the courts have interpreted that term to exclude purely monetary harm.[22] As for damage to wells from being shut-in, we have already made clear that Opinion No. 239 does not preclude continued production of oil and gas in conformance with NGA dedication and NGPA pricing requirements, or for testing purposes. Moreover, damage to the rare well that could not lawfully produce any hydrocarbons under Opinion No. 239 is uncertain to occur, and the possibility of such damage is couched in terms of speculation and condition.[23] The applicable

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[20]Stay Memorandum at 19.

[21]*See, e.g.*, Northern Natural's August 13, 1985, Answer at 7.

[22]*See, e.g.*, Wisconsin Gas Co. v. FERC, 758 F.2d 669 at 674 (D.C. Cir. 1985), *citing Virginia Petroleum Jobbers*, 259 F.2d at 925.

[23]*See* Stay Memorandum at 20-23 and Staff's August 13, 1985, Answer at 18.

case law requires that the alleged harm "is certain to occur in the near future."[24]

Stowers' assertions that competition and conservation in the Panhandle Field will be harmed absent a stay are without foundation. Indeed, the present harm to Dorchester's wells and to dedicated reserves far outweighs the speculative harm to Stowers. Opinion No. 239, if anything, encourages *legal* competition in the Panhandle Field. By preventing further violations of the NGA and/or NGPA, Opinion No. 239 eliminates competitive imbalances and untoward practices that flow from the violations of those statutes. As for the assertions regarding conservation, the allegation that the RRC has made an "inherent" finding that the wells drilled by Stowers are "necessary for the efficient drainage of the Panhandle West Gas Field"[25] is incorrect. To our knowledge, such "effective and efficient" findings have not been explicitly made by the RRC as required by our regulations and the NGPA; if made in the future, these findings must be made explicitly, in accordance with the regulations and the NGPA, based on substantial evidence.

(c) *Harm to Other Parties*

The bankruptcy issues raised by Stowers actually militate *against* a stay. A stay would allow continued production and would permit the diversion of low-priced gas dedicated to the interstate market to continue. This would harm both the rightful owners of that gas and the consuming public.

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[24]Wisconsin Gas Co. v. FERC, 758 F.2d 669 at 674 (D.C. Cir. 1985).

[25]Stay Memorandum at 23-24.

Moreover, the harm caused by a stay to Dorchester and Northern is more than just monetary. Northern would be deprived *permanently* of the volumes of dedicated natural gas that would be diverted from the subject acreage by respondents during a stay. It is immaterial whether Northern is taking the gas now or will take it in the future. The harm is the permanent loss of the diverted volumes, and this harm affects both Dorchester as seller and Northern and its customers as purchasers.

(d) *The Public Interest*

Stowers states that the public interest would be served by a stay because a stay (1) would be consistent with the purpose and intent of section 103 of the NGPA, (2) would be consistent with the statutory provisions deferring primary conservation and resource determination to the states, (3) would continue Commission policy of deferring to states for the interpretation of state law, (4) would be consistent with basic concepts of resource conservation by preventing the shutting-in of wells needed to effectively and efficiently drain the field, and (5) would enhance competition.

We have already addressed the conservation and competition issues raised by Stowers. However, we will briefly address Stowers' section 103 contentions. The policies underlying the NGPA and section 103 which limit incentive prices to *new* gas production argue for *denying* a stay. As already noted, Opinion No. 239 does not intrude on purely state areas, but acts in supervening areas of *federal* law which are this Commission's sole responsibility. It is this Commission's Congressional mandate to protect the public interest by preventing diversion of low-cost natural gas from the interstate market in violation of

the NGA and to prevent violations of Title I of the NGPA.

Accordingly, the motions for stay will be denied.

B. *Requests for Rehearing*

The requests for rehearing attempt to reargue positions taken before the presiding judge during the initial hearing and in briefs on exceptions. These may be summarized as follows: (1) The Commission is without jurisdiction, under the NGA and NGPA, to issue Opinion No. 239. (2) The Commission improperly interpreted state law and regulations under the NGA and NGPA. (3) The hearing process and Opinion No. 239 were procedurally flawed. We disagree with each of these specifications of error and deny the requests for rehearing as discussed below.

1. *Jurisdiction*

The Commission has exclusive statutory jurisdiction over the sales and pricing of the dedicated reserves in this proceeding and only the Commission can take enforcement action to assure compliance with the sales and pricing requirement under Federal law. Opinion No. 239 is consistent with the requirements of NGA section l(b) and NGPA sections 601(a) and 503(d).

(a) *NGA section l(b)*

Section l(b) of the NGA provides that the Commission's regulatory authority under the NGA "shall not apply . . . to the production or gathering of natural gas." However, controlling precedent makes clear that the limitation in section l(b) is to be very narrowly construed.[26]

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[26]Unlike the narrow exclusion of section l(b), section 7(b)
(Footnote continued on next page)

In *Phillips Petroleum Co. v. Wisconsin, (Phillips v. Wisconsin)*[27] the Supreme Court made clear that section 1(b) does not deprive the Commission of jurisdiction over the rates charged for sales of dedicated interstate reserves merely because production and gathering are involved. There is a common sense distinction between direct federal regulation of production, and the indirect consideration of production activities that may be relevant to a determination of whether and to what extent Federal law has been violated.[28] The Commission has jurisdiction to determine whether gas which has been dedicated to interstate commerce is being unlawfully diverted and/or illegally priced.[29] As the administrative law judge correctly noted in the Recommended Decision, "dedication" attaches not to an individual sale or producer but to the gas itself.[30] In *Phillips v.*

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of the NGA broadly prohibits the abandonment of any service dedicated to interstate commerce "without the permission and approval of the Commission." 15 U.S.C. § 717(b) and § 717f(b) (1982).

[27]347 U.S. 672 (1954), *reh'g denied*, 348 U.S. 851 (1954).

[28]*See* Colorado Interstate Gas Co. v. FPC, 334 U.S. 581, 602-03 (1945); see *also* Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378 at 389 (1959) (Once gas is dedicated to interstate commerce, "there can be no withdrawal of that supply from continued interstate movement without Commission approval").

[29]United Gas Pipe Line v. McCombs, 442 U.S. 529 (1979); California v. Southland Royalty Co., 436 U.S. 519 (1978); Mitchell Energy Corp. v. FERC, 533 F.2d 528 (5th Cir. 1976).

[30]Recommended Decision, 30 FERC ¶ 63,017 at 65,044 (1985), *citing* Hunt v. FPC, 306 F.2d 334, 342 (5th Cir. 1962), *reversed_on_other_grounds*, 376 U.S. 515 (1964); Opinion No. 737, 54 FPC 145, 149 (1975).

Wisconsin the Court concluded that independent producers are "natural gas companies" under the NGA, and their sales in interstate commerce of natural gas for resale are subject to the jurisdiction of, and regulation by, the Commission. This jurisdiction is not exempted by section 1(b), because the "production and gathering" functions end before the sales in interstate commerce begin.

The Supreme Court cases cited by applicants[31] to support their position were decided *prior* to *Phillips v. Wisconsin*. These very cases were alluded to by the Court in *Phillips v. Wisconsin* in 1954 in the process of the Court's *narrowing* of the operation of the NGA section 1(b) exclusion.

As the presiding judge stated in *Stowers*:

> [t]he Commission is not attempting to regulate respondents' production activities but is investigating whether respondents violated and are violating federal statutes. Sections 14, 16 and 20 of the NGA and Sections 501 and 504 of the NGPA authorize Commission action to end violations of the respective statutes . . . . [R]espondents' position . . . would lead to the absurd result that the Commission is powerless to determine whether producers are violating Federal law that Congress

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[31]*See, e.g.*, Motion for Rehearing of the State of Texas at 1, *citing* FPC v. Panhandle Eastern Pipe Line Co., 337 U.S. 498, 518 (1949) and Interstate Natural Gas Co. v. FPC, 331 U.S. 682, 690 (1947), *reh'g denied*, 332 U.S. 785 (1947).

determined the Commission alone should enforce.[32]

(b) *NGPA section 601(a)*

The respondents argue that even if the limitations of NGA section 1(b) are inapplicable, the Commission's NGA jurisdiction over respondents' gas sales is removed by section 601(a) of the NGPA.[33] We disagree.

Specifically, section 601(a)(l)(B)(iii) of the NGPA provides that the Commission's Natural Gas Act jurisdiction:

> shall not apply solely by reason of any first sale of natural gas which is committed or dedicated to inter state commerce as of the day before the date of enactment of this Act and which is --
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> *   *   *
>
> . . . natural gas produced from any new, onshore production well (as defined in section 103(c) of this Act).[34]

The judge correctly determined that respondents' final section 103 determinations only covered gas from oil proration units, that is, gas indigenous to an oil stratum and produced from that stratum with oil. The judge correctly determined that the sale of gas well gas from these units was not covered by the NGPA section

[32]Recommended Decision, 30 FERC ¶63,017 at 65,044 (1985).

[33]*See, e.g.* Request for Rehearing of Stowers Oil and Gas Company, *et al.* at 26-28.

[34]15 U.S.C. § 3411(a)(l)(B)(iii) (1982).

503 determinations for pricing under section 103.[35] If their wells produced dedicated gas as well, that gas was not subject to the section 103 determinations because the dedicated gas devolved to Dorchester under the applicable instruments of conveyance as discussed in the Recommended Decision. Accordingly, the arguments on rehearing that this gas was also covered by the section 103 determinations in order to remove the Commission's jurisdiction under section 601(a) is totally without substance. The section 103 determinations simply do not extend to *all* the gas being produced from the respondents' wells. We reaffirm that:

> [t]he evidence shows that most respondents' wells are producing gas which Dorchester would otherwise produce from its existing proration units and *the Railroad Commission has made no finding that respondents' wells are necessary to effectively and efficiently drain that portion of the reservoir from which Dorchester's wells are producing gas*. According to the [sic] NGPA Section 103(c), these respondents are therefore *not* entitled to a

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[35]Applications asserting error because the determination of what constitutes casinghead gas was not made in a rulemaking context are wide of the mark. *See, e.g.* Application of Respondent J. B. Watkins for Rehearing of Opinion No. 239 at 27. The presiding judge applied the plain language of the state's own statutory definition of the term in the course of determining whether NGA and/or NGPA violations were occurring. No *federal* rule or definition of "casinghead gas" was independently adopted such that the APA requirements would apply or a prospective limitation somehow adhere to the determination. The judge merely applied the NGA/NGPA requirements to the respondents. These requirements were applicable during the entire course of the production activities at issue, not only prospectively from the date of the Recommended Decision or Opinion No. 239.

Section 103 well category determination for gas from the Dorchester proration units. [Emphasis supplied.][36]

We note that the section 103 determination applies to only certain gas consistent with the legislative history surrounding that section.

It is clear from the legislative history that the section 103 price was not intended to apply to gas that could be produced by an existing well. As Senator Hollings stated (concerning what later became section 103 gas), "let us not set up a temptation . . . to start punching holes in existing reservoirs . . . and calling it

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[36]Recommended Decision, 30 FERC ¶ 63,017 at 65,047 (1985). Not withstanding applicants' assertions to the contrary, this Commission's current practice does not recognize that the RRC may make "implicit" findings that a well is necessary to "effectively and efficiently" drain a proration unit. An actual, explicit finding based on substantial evidence is required, whether as part of an RRC Rule 38 exception or otherwise. The only type of acceptable "implicit" finding that a well was needed to effectively and efficiently drain a portion of an existing proration unit would be for *second* wells in a proration unit which are spudded after February 19, 1977, and before January 1, 1979, or for which a drilling permit was issued before January 1, 1979. The Commission permitted such "implicit" findings for wells drilled in existing proration units during that transitional period, because its rules implementing the NGPA were not in place until December 1978. However, only three of the respondent wells were drilled during that period, and the case cited by Stowers, at page 33 of their request for rehearing, *George R. Schurman Norris SUA Baker No. 2 Well*, 8 FERC ¶ 62,098 (1979) is therefore generally inapposite, because the Baker No. 2 well was spudded on December 22, 1978, and was subject to the transitional rule. However, even as to those three wells (Komanche Cobb #2, 3, & 4), it is clear that the RRC made no implicit effective and efficient finding as asserted, because the RRC determinations for these three wells considered them to be the *first* wells in oil proration units.

new gas."[37] Also, Senator Pearson stated, as part of the floor debate, that what was to become section 103 prices should only apply to "natural gas sold from new reservoirs and extensions of existing reservoirs . . . . The economic incentives . . . should only be applicable to truly new gas discoveries."[38]

The fact that Dorchester may have received "effective and efficient" findings for some of its own section 103 wells is irrelevant to the issue of the extent of the gas production covered by respondents' own section 103 determinations. Since respondents operate section 103 *oil* wells, their section 103 determinations only cover gas indigenous to an oil stratum and produced from that stratum with oil. Dedicated dry gas that may be produced from their wells would require an explicit "effective and efficient" drainage finding in order to receive the section 103 price, as opposed to the section 104 price.[39] Moreover, the title to "dry" gas and the proceeds therefrom would need to be resolved in an appropriate forum if produced from respondents' oil wells, even if an explicit "effective and efficient" drainage finding were obtained. Hence, the NGPA section 601(a) jurisdictional exclusion would only apply to authentic casinghead gas that was part of respondents' oil rights, and not to the dry gas dedicated to interstate commerce through Dorchester.

(c) *NGPA section 503(d)*

Various applicants argue that Opinion No. 239 retroactively reverses the respondents' section 103 determinations contrary to NGPA section 503(d). This is a mischaracterization of the Commission' Opinion.

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[37]121 Cong. Rec. S33589 (daily ed. Oct. 22, 1975).

[38]123 Cong. Rec. S30373 (daily ed. Sept. 22, 1977).

[39]18 C.E.R. § 371 305(b)(1) (1985).

The section 103 determinations could not apply to gas that was not part of respondents' oil rights which they did not own. Thus, the section 503(d) procedures, which pertain to review of well category determinations, are not relevant to determining whether the otherwise applicable price ceilings are being exceeded.

Under the broad Congressional implementing authority of NGPA section 501 and NGA section 16,[40] the Commission has the authority *and responsibility* to confirm the limitations of respondents' section 103 classifications to gas that was part of their oil proratic units and produced from below the gas-oil contact in their wells, so as to be indigenous to an oil stratum and produced from that stratum with oil.

There was no reason to reopen the determinations, since they applied to the gas lawfully produced from respondents' wells as casinghead gas. The point is that these determinations were correct -- the gas was section 103 gas insofar as it was true casinghead gas. There was no reason or need to reopen the determinations because the situation *did not warrant* reopening under the regulations.

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[40]Such broad grants of authority have been held "not restricted to procedural minutiae, and [to] . . . authorize means of regulation not spelled out in detail, provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act." Mesa Petroleum Co. v. FPC, 441 F.2d 182, 187 (5th Cir. 1971) *citing* Niagara Mowhawk Power Corp. v. FPC, 379 F.2d 158. *See also* Public Service Com'm of State of N.Y. v. FPC, 327 F.2d 893, 897 (D.C. Cir. 1964). (Section 16 of Natural Gas Act held to provide a basis for the Commission to cope with unforeseen problems, and is not confined to procedural regulations, but is a broad grant of authority).

2. *State Law Issues*

(a) *Joint Board*

Various applicants assert that the failure of the Commission to convene a "joint board" with state authorities under NGA section 17 was reversible error.[41] However, Congress clearly intended use of such a board to be discretionary, and even provided that the Commission could, in its sole discretion, revoke any referral to such board: "The Commission *may* refer any matter arising in the administration of this act to a [joint] board . . . . The Commission *may*, when *in its discretion* sufficient reason exists therefor, revoke any reference to such a board." [Emphasis supplied.][42] Another reason convening a joint board was unnecessary is that the section 103 determinations were valid insofar as they applied to respondents' true casinghead gas. Full scale reopenings, and complex and lengthy joint board proceedings simply are not warranted for valid section 103 determinations.

The Commission did, however, seek the advice and counsel of the RRC both in the spirit of comity and in the furtherance of expeditiously dealing with this important matter. The RRC declined participation,[43] but did agree to advise this Commission in writing of related matters before the RRC. We believe this procedure was a reasonable and more efficient alternative to the joint board, which was a discretionary option not needed under the

[41]*See, e.g.*, Request by Prairie Oil Company, et al. for Rehearing of Opinion No. 239 at 20-21.

[42]15 U.S.C. § 717p(a) (1982).

[43]Letter from Walter Earl Lilie (RRC Special Counsel) to Kenneth F. Plumb (FERC Secretary) (June 11, 1985).

circumstances. Given the immediate need to correct the ongoing violations of the NGA and/or NGPA, and the fact that no reopening of the section 103 determinations was necessary, it was a proper exercise of discretion not to convene a joint board. Assertions that this decision is arbitrary and capricious, or an abuse of discretion are without foundation.[44]

(b) *Abstention*

Applicants generally, and the State of Texas particularly, argue that the Commission should have abstained from acting until Texas had first resolved every tangential state law issue to its satisfaction. Relying, as do other applicants, on cases such as *Burford v. Sun Oil*,[45] Texas argues that it was error for the Commission not to abstain until the various Texas tribunals reached authoritative rulings on issues of state law. However, this Commission believes that the various Texas tribunals *had* reached authoritative rulings on related issues of state law. Even if they had not reached authoritative rulings on all issues, applicants' reliance on *Burford* and related cases is misplaced, and the Commission need not have stayed its hand further, given the circumstances of the *Stowers* proceeding.

The Supreme Court has made it clear that the doctrine of abstention is "the exception, not the rule"

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[44]*See generally* 73A C.J.S. § 247 at 369 ("The ultimate choice of procedure by an agency in making its orders is not ordinarily subject to judicial revision." [footnote and citations omitted]).

[45]319 U.S. 315 (1943).

and "an extraordinary and narrow exception" at that.[46] The Court has indicated that "[t]he abstention doctrine is not an automatic rule applied whenever a federal court is faced with a doubtful issue of state law; it rather involves a discretionary exercise of a court's equity powers."[47]

Applicants' reliance on *Burford* and similar cases is simply misplaced. *Burford*, for example, concerned a state system for review of RRC orders, and the Court held that a federal court that had scant expertise in oil and gas matters should abstain from reviewing the reasonableness of a well spacing order. This is unlike the *Stowers* proceeding, where federal law governs, the federal agency has exclusive jurisdiction, and the expertise to administer the statutes entrusted to it. It is this Commission that has supervening jurisdiction over issues of NGA and/or NGPA compliance, and the Texas regulatory scheme is integral but subordinate to the federal scheme. Accordingly, here *federal* law provides the rule for a decision on the merits, and abstention is not warranted.[48]

(c) *Opinion No. 239 is Consistent with State Law and RRC Rules*

Applicants variously state that it was error for Opinion No. 239 to define "casinghead gas" as it did,

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[46]Colorado Water Conservation District v. U.S., 424 U.S. 800, 813, *reh'g denied*, 426 U.S. 912 (1976) (*quoting* County of Allegheny v. Frank Mashuda Co., 360 U.S. 185, 188-89 (1959).

[47]Baggett v. Bullitt, 377 U.S. 360, 375 (1964).

[48]*See Moses H. Cone Memorial Hospital v. Mercury Construction Corp.* 460 U.S. 1, 23 (1983). (The Court held that where there is substantial doubt that the parallel state proceeding will result in prompt resolution of the issues, it would be an abuse of discretion by the federal forum to stay its hand).

and to use the gas-oil contact to demarcate dedicated gas reserves from undedicated gas reserves.[49] In addition, the RRC states that the presiding judge erroneously refers to the Panhandle Field as a "common reservoir," and states that its recent actions do not support the position taken by this Commission in Opinion No. 239.[50] We disagree with these statements.

(i) *Casinghead Gas*

The presiding judge (and this Commission) utilized the Texas statutory definition of casinghead gas which is also used in the RRC's own statewide rules,[51] namely "any gas and/or vapor indigenous to an oil stratum and produced from the stratum with oil."[52] The gloss that applicants seek to ascribe to that definition is based on generalized statements in annual

[49]*See, e.g.*, Request for Rehearing of Stowers Oil & Gas Company, *et al.*, at 39-56. Arguments that this Commission has erroneously subdivided strata, or mistakenly divided reservoirs vertically are part of applicants' assertions that the Commission used the wrong definition of casinghead gas in separating dedicated from non-dedicated gas at the gas-oil contact. The essence of *all* these arguments is that this Commission did not properly construe the Texas statutory definition of casinghead gas in demarcating dedicated from non-dedicated gas reserves at the gas-oil contract. Gas from a completion below the gas-oil contact would be indigenous to an oil stratum and produced from the stratum *with* the oil.

[50]*See* RRC Request for Rehearing at 4-7.

[51]Tex. [Nat. Res.] Code Ann. § 86.002(1) (Vernon 1978); Railroad Commission of Texas, Oil & Gas Division, Rules Having State- wide General Application to Oil, Gas and Geothermal Resources Operations Within the State of Texas (Definition 13).

[52]Recommended Decision, 30 FERC ¶ 63,017 at 65,046 (1985).

reports of the RRC and a state attorney general's 1940 letter written regarding circumstances inherently different from those in the *Stowers* proceeding. In the past, when federal courts in the state of Texas[53] and Texas state courts[54] applied the statutory definition, they applied the same definition as written and as applied in Opinion No. 239.

Even if the state statutory definition of casinghead gas were inconsistent with Opinion No. 239 (and it is not), we would not be constrained to use it if its adoption would frustrate implementation of the federal statutes.[55] The presiding judge recognized this fact in stating that the Commission, as a matter of law, would not be bound to apply a state definition "if such definition was unreasonable on its face; or if its adoption would necessarily frustrate implementation of the purpose of the federal statutes[.]"[56]

(ii) *Gas-Oil Contact*

Applicants claim that it was error for the Commission to use the gas-oil contact as the dividing

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[53]Clymore Production Co. v. Thompson, 13 F. Supp. 469 (W.D. Tex. 1936).

[54]Dorchester Gas Producing Co. v. Harlow Corp., *et al.*, Case No. 84-505910, 99th Judicial District, Lubbock County, Texas (Exhibit 616).

[55]*See, e.g., United Gas Improvement Co. v. Continental Oil Co.*, 381 U.S. 393, 400 (1965). *See also Blair-Vreeland*, 53 FPC 843, 853 (1975), *reversed on other grounds*, *Vreeland v. FPC*, 528 F.2d 1343 (5th Cir. 1976) ("[W]e cannot give effect to a state law when to do so would interfere with the discharge of our responsibilities under the Natural Gas Act.").

[56]Recommended Decision, 30 FERC ¶ 63,017 at 65,046 (1985).

line between dedicated and non-dedicated reserves. They generally assert that it is a "hypothetical" concept, contrary to state practice, and that it "cannot be determined and enforced consistently." In addition, applicants make vigorous procedural objections to the introduction of the concept.[57]

The state's own rules discuss the "gas-oil" contact so the concept can hardly be termed unexpected or "hypothetical," or contrary to state practice. As the presiding judge noted, the RRC rules provide:

> (B) Isolation of Associated Gas Zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact. (Statewide Rule 13(b)(4)(B) (Exhibit 531 at 2)).[58]

We believe this lends strong support to Opinion No. 239's approach.

Further, the fact that the gas-oil contact was identified in only one of the subject wells during the proceeding, does not mean that well operators are unable to make that determination directly as provided by the Statewide Rule. It only means that given the exigencies of litigation and discovery, Staff located it "directly" in only one instance (Exhibit 74) but could

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[57]*See, e.g.* Request for Rehearing of Stowers Oil and Gas Company, et al. at 49-56.

[58]Recommended Decision, 30 FERC ¶ 63,017 at 65,028 (1985).

indirectly use secondary evidence to approximate its location for all of respondents' other wells.[59]

Applicants' procedural objections to the use of the concept are that it involved a "change of theory" by Staff, that it is not mentioned in the show cause order, and that the judge should have permitted yet another round of testimony to permit a new witness to testify on the concept. We disagree.

Contrary to these assertions, the show cause order set the inquiry broadly enough to encompass the concept of the gas-oil contact, and in our view, the rebuttal testimony objected to was simply that, *i.e.* rebuttal testimony, and was in no way procedurally improper. The show cause order, for example, contradicts these "change of theory" assertions by alleging that "the brown dolomite stratum is productive only of dry gas at the level at which the operators of each of the [subject] oil wells . . . have perforated or have caused the perforation of such oil wells."[60] This does not imply that the brown dolomite could not produce commercial quantities of oil in a low-lying part of the field. Thus, when Staff rebutted the presence of commercially producible oil in the brown dolomite *in the subject acreage* in part by using the gas-oil contact argument, this did not depart from the show cause order.

In any event, an administrative order initiating a show cause proceeding is not required to be definitive as to every detail that may arise in a later hearing. Although there was no change of theory or departure from the show cause allegations here, even if there had

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[59]Recommended Decision, 30 FERC ¶ 63,017 at 65,048 (1985).

[60]26 FERC ¶ 61,207 at 61,478 (1984).

been to a certain degree, this is permissible where, as here, respondents had adequate general notice of the scope of the proceedings.[61]

(iii) *Texas Railroad Commission*

The Commission reiterates its view that the decisions on LTX units and on "high perforations" reached by the RRC in the *Phillips* proceeding[62] and in the July 8, 1985, public meeting are consistent with Opinion No. 239. While the RRC may not have reached a decision on *all* conceivable issues related to completion practices in the Panhandle Field, the important decisions have been reached. Namely, (1) LTX units may not be used to meet or maintain an oil well classification, and those oil wells that utilized such refrigeration units must be retested, and (2) any oil well reperforated into a dry gas zone must be retested to show the producing capacity and gas-oil ratio, and compliance with applicable rules, orders and statutes.

Having declined our earlier invitation to participate meaningfully in this proceeding, the RRC now claims on rehearing that our decision will have the practical effect of intruding on its regulation of gas and oil completion and production practices in Texas. Specifically, it claims that we have misconstrued the definition of casinghead gas under Texas law because the RRC "has not stated that the existence of perforations above the gas-oil contact in an oil well is in every instance a violation of RRC rules" and has not concluded that "production of gas from above the gas oil contact through perforations below the gas-oil contact

[61]*See* K. Davis, Administrative Law Treatise § 8.04 (Supp. 1983); 2A Moore's Federal Practice § 8.03 (2d ed. 1984).

[62]RRC Oil and Gas Docket No. 10-77,314.

is improper." (Pet. 5, p.6.) We find this argument unpersuasive.

Contrary to the RRC's claim, our decision does not find that perforations above the gas-oil contact in an oil well violate RRC rules *in every instance*, nor does it reach any broad conclusions about the production of gas from above the gas-oil contact through perforation below the contact. *Stowers* dealt with 37 specific producers and 196 particular oil wells. The subtle points the RRC now raises were simply not the subject of the controversy between the parties. The producers claimed that all gas produced by an oil well was casinghead gas so long as the well met the overall gas/oil ratio for the Texas Panhandle District, and that it was therefore irrelevant whether perforations were made above the gas-oil contact and whether the gas was produced from a stratum that contained no oil in commercial quantities. At the time of the hearing, none of the producers claimed the defense that there had been a shift in the gas-oil contact in any well after their perforations were made or that they were producing gas from above the contact through perforations below the contact issues the RRC now raises as being unsettled. Accordingly, the *Stowers* decision does not address these issues and in no way interferes with the RRC's ability to deal with them.

On the other hand, the RRC's recent pronouncements on high perforations fully support the findings of Judge Murray and the Commission on the general definition of casinghead gas under Texas law and clearly reject the position argued before us by the producers. The *Stowers* decision is thus entirely consistent with Texas law and regulation.

Next, we reject the RRC's argument that we should refrain from construing the definition of casinghead gas under Texas law until the RRC has

finished its review of this question. We have already observed that *Stowers* involves Federal issues over which the Commission has exclusive jurisdiction. We have considered the Texas definition of casinghead gas because it is relevant to the determination of whether or not Federal law has been violated. When the Commission instituted this case, there was no ongoing RRC proceeding on the "high perforations" issue. Indeed, the RRC's own staff has conceded that the RRC had not been enforcing the casing perforation rules in the Panhandle field.[63]

It would be irresponsible for this Commission to allow violations of federal statutes to continue until the RRC finished what promises to be a "lengthy"[64] review to fill in every ancillary detail. The difference between the RRC's rescinded June 10, 1985, memorandum and the RRC's memorandum issued July 8, 1985, regarding "high perforations" is not disagreement over the interpretation of "casinghead gas" or "high perforations" or whether LTX units may be used to maintain an oil well classification; rather, it appears the RRC wants to investigate each individual case to see if an actual violation is occurring.

Finally, the RRC asserts that there was error in the presiding judge's reference to the Panhandle Field as a "common reservoir." A careful reading of the record[65] and the Recommended Decision show that the reference has not been used as a "designation" regarding the physical characteristics of the field, but

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[63]Transcript of the RRC Oil and Gas Conference on July 8, 1985, on the High Perforation Issue, p. 13.

[64]RRC Request for Rehearing at 7.

[65]*See, e.g.*, Tr. 1337-39, Exhibits No. 73 and 265.

that the judge merely noted the language used by the RRC in its 1935 "common reservoir" order.[66]

3. *Procedural Objections*

Applicants' procedural objections generally go either to Opinion No. 239 or to the conduct of the hearing by the presiding judge, and the disposition of interlocutory appeals by the Commission.

(a) *Opinion No. 239*

Applicants assert Opinion No. 239 is not based on substantial evidence and lacks a rational basis, because it adopted the Recommended Decision without extensive further discussion.[67] It is also asserted that the adoption and issuance of Opinion No. 239 violated the Government in the Sunshine Act.[68] As was indicated in the part of this order discussing motions for stay, these allegations are unfounded.

The Recommended Decision was based on extensive and substantial evidence presented in seventeen days of hearings from July 24, 1984, through August 17, 1984. Over 600 exhibits were admitted, and the transcript exceeded 3,800 pages with a total record of approximately 20,000 pages. Testimony was submitted by forty-two witnesses, thirty-four of whom testified on behalf of respondents. In addition, the Commission considered numerous briefs on exceptions

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[66]Exhibit 307.

[67]*See, e.g.*, Application for Rehearing of Cabot Pipeline Corporation at 12-14; Request for Rehearing of Stowers Oil and Gas Company, *et al.* at 67-70.

[68]5 U.S.C. § 552b (1982). Request for Rehearing of Stowers Oil and Gas Company, *et al.* at 79-82.

which essentially restated arguments made at the hearing level. There is nothing that bars the Commission from adopting, without an additional extensive discussion, the analysis of the judge's recommended decision as its own including all findings of fact, conclusions of law, and the application of the facts to the law, as provided by section 8(c) of the Administrative Procedure Act.[69] This is what the Commission did upon issuance of the order in *Stowers*.

Applicants' assertions regarding the Government in the Sunshine Act are not valid, given accepted interpretations of that Act. In *Communications Systems, Inc. v. FCC*,[70] the court rejected a similar argument and held that the legislative history of the Act indicated that Congress intended to allow agencies to act on matters that are circulated among members sequentially in writing. The court specifically held that the agency "was not in violation of the Sunshine Act . . . when it used its notation procedure to dispose of [a] petition."[71]

Finally, brief mention need be made of Prairie Group's assertion that Opinion No. 239 is flawed

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[69]5 U.S.C. § 557(c) (1982). The Act requires that decisions include a statement of findings and conclusions and the reasons therefor. It is settled law that an agency may adopt a subordinate hearing examiner's statement as its own. *See, e.g.*, Carolina Freight Carriers Corp. v. U.S., 307 F. Supp. 723 (W.D.N.C. Charlotte Division, 1969): "It is now settled law that when the Commission finds no material error in the statement of facts and the conclusions thereon of the Joint Board or hearing examiner, it is not required to prepare a detailed report, but may affirm and adopt the report of such board or examiner as its own." 307 F. Supp. at 727.

[70]595 F.2d 797 (D.C. Cir. 1978).

[71]*Id.* at 800.

because we allegedly cannot order respondents to cease and desist their unlawful practices. We view Prairies Group's construction of section 16 of the NGA (and similarly section 501 of the NGPA) as too narrow. These types of provisions have not been limited to procedural *minutiae* but are broad grants of authority.[72] Furthermore, we do not anticipate that the Prairie Group or any other respondents will not follow the directives of Opinion No. 239. In any event, Opinion No. 239 also directs Staff to take all necessary action to accomplish the cessation of the NGA and NGPA violations, which would include initiating the type of court proceedings alluded to by the Prairie Group.

(b) *Hearing Process*

Applicants assert numerous instances of what they perceive to be procedural error at the hearing level, in effect alleging that every ruling adverse to them was reversible error. The Prairie Group presents the most complete list of such allegations[73] which includes allegations that the burden of proof was misallocated, that the exclusion of certain proposed testimony was error, that the judge's reliance on other testimony was error, and that not dismissing certain wells from the proceeding was error. We carefully considered the allegations of procedural error and can discern no grounds for reversal.

(i) *Burden of Proof*

The presiding judge spoke respecting the burden of proof as follows:

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[72]*See* n.40 *supra*.

[73]Request by Prairie Oil Company, *et al.* for Rehearing of Opinion No. 239 at 22-38.

> . . . evidence is usually so persuasive in one direction or other that arguments about who has the burden of persuasion are meaningless. In any event, we will save arguments on the ultimate burden of persuasion for briefs.[74]

Recently, we concurred in that statement, noting that the presiding judge may make a ruling on allocating the burden of persuasion, "if the need for such a ruling arises."[75] In this case, the weight of the evidence was that Staff's burden of persuasion was clearly met and there was no error. As the judge noted, the evidentiary presentation of the expert witnesses sponsored by Enforcement Staff and Dorchester was totally persuasive and convincing.[76] We agree.

(ii) *Excluded Testimony*

Applicants counter that the reason evidence was so persuasive is that testimony favorable to respondents was excluded. This allegation is specious. Applicants particularly object that a subpoena was not issued for Mr. W. A. Murray, so that he could give still further testimony after Staff's rebuttal testimony. We believe the judge acted properly in denying the subpoena while allowing testimony from Mr. Murray into the record as an offer of proof. At some point in

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[74]Disposition of Pending Motions, Stowers Oil & Gas Company, *et al.*, issued March 26, 1984, at 3.

[75]Order on Motion for Emergency Relief, Stowers Oil & Gas Company, *et al.*, Docket No. GP84-23-001, issued August 9, 1985. 32 FERC ¶ 61,217 at 61,496.

[76]Recommended Decision, 30 FERC ¶ 63,017 at 65,048 (1985).

litigation, there must be an end to testimony and a closure of the case for decision. Since we find that Staff had not made any abrupt change on rebuttal as alleged, but had merely rebutted respondents' case, denial of the subpoena was proper. The judge fairly entered the testimony into the record as an offer of proof for consideration by the judge and this Commission.

Applicants also object that they were not allowed to depose Mr. Howard Kilchrist, the Commission's Director of the Division of Producer Audits and Pricing. However, applicants were permitted to file interrogatories of Mr. Kilchrist. We continue to believe that this procedure struck a fair balance and permitted respondents to obtain what information they needed, without having the chilling effect on governmental deliberation that the deposition process would have imposed.[77]

(iii) *Credibility of Staff Witnesses*

Applicants attack the credibility of the staff witnesses, especially Mr. Clark Gillespie.[78] During a hearing, the presiding officer is in the best position .to gauge the credibility of witnesses, to observe their demeanor, and to be sensitive to the countless factors that are vital to the hearing process, which are absent from the bare words of the record that is ultimately reviewed. Applicants, who are litigants with vested interests in the outcome, cannot reasonably be permitted to substitute their views on the evidence for those of the impartial trier of fact.

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[77]See 28 FERC ¶ 61,138 (1984).

[78]Request by Prairie Oil Company, et al. for Rehearing of Opinion No. 239 at 31-32.

A careful review of the record indicates that applicants' assertion that staff witness, Mr. Clark Gillespie, had previously testified before the RRC contrary to his testimony in the Stowers proceeding is unfounded.[79]

(iv) *Prairie Group/Lucky Bird/J.B. Watkins Wells*

Prairie Group asserts that twenty-one of its wells should have been dismissed from the proceedings because they were only perforated in the granite wash. However, if such wells are capable of draining Dorchester's dedicated gas, then NGA/NGPA violations have occurred nonetheless. The Recommended Decision (Appendix B) acknowledges that there are some respondent wells not completed in the brown dolomite. However, in discussing these wells, it is pointed out, for example, that "Wy-Vel Coffee No. 1 and Hodges No. 2 [Prairie Group wells] are perforated in granite wash *up to the base of the brown dolomite*,"[80] and Caprock Zack No. 1, Kaari Future Nos. 3 and 1-5, and Raven Snapp No. 4 "are *open to production in the brown dolomite*,"[81] [emphasis added] although listed in Appendix B as "not in" the brown dolomite. Analysis is also provided for the other wells in the group. Accordingly, we are persuaded by the careful analysis in Appendix C that it was not error to keep these, and other Prairie Group wells in the proceedings. To the extent any of the Prairie Group's wells are not in violation of the NGA

[79]The Reply Brief of Enforcement Staff and Dorchester Gas Producing Company at 114-122 persuasively rebuts these assertions.

[80]Recommended Decision, Appendix C, mimeo at 8-10, 30 FERC ¶ 63,017 at 65,055-57 (1985).

[81]*Id.*, Appendix C, mimeo at 10.

and/or NGPA, gas production may continue to the extent it is casinghead gas.

Lucky Bird also claims that its wells are exceptions and should have been dismissed from the proceedings. However, Lucky Bird's Thornburg leases have gas processing refrigeration units (LTX units) of the type covered by the RRC's *Phillips* decision. Lucky Bird states that it cannot permit RRC tests of its wells under *Phillips* because of Opinion No. 239. As discussed earlier, this conclusion is erroneous. Lucky Bird's wells may be tested by the RRC to determine whether gas currently is being reported as "oil" and thus clarify the issue respecting the Thornburg lease. Given the evidentiary analysis in the Recommended Decision's Appendix C respecting these wells, and the conflicting statements surrounding them, we find no error in not dismissing these wells from the proceedings. Additionally, Dorchester states that Lucky Bird has informed the RRC that its wells do not require testing under the RRC order because they "originally were potentialed without the use of the refrigeration unit."[82] Consequently, Lucky Bird's contention that Opinion No. 239 prevents its wells from being tested, or will cause them to be shut-in is moot.

J.B. Watkins essentially reargues its case with respect to its wells. We believe the judge acted reasonably with respect to Watkins and that the evidence, contrary to Watkins' assertions, was not so "equivocal" as it asserts. It is still "quite possible" as the judge noted, that Watkins is in violation of the federal statutes.[83] The course of action taken, testing of

[82]*See* Answer of Dorchester Gas Producing Company in Opposition to Supplemental Motion for Stay of Lucky Bird Petroleum, filed August 26, 1985, at 2.

[83]Recommended Decision, 30 FERC ¶ 63,017 at 65,049
(Footnote continued on next page)

Watkin's wells before making a final decision is reasonable under the circumstances, and is neither arbitrary and capricious, nor works to deprive Watkins of due process.

(v) *Other Allegations*

A number of allegations of error are raised, including the failure of the judge to allow certain recross, to allow certain hearsay testimony, to give certain time extensions, and to move the hearing to Amarillo, Texas. We find these objections are without substance. Written pleadings or oral statements responsive to the motions to allow the recross, hearsay testimony, extensions of time, and change of venue to Amarillo are part of the record. We find the judge's rulings on these points to be reasonable.

Prairie Group also states that the Freedom of Information Act (FOIA) required the disclosure of certain documents otherwise privileged. Specifically, the applicants state that FOIA requires disclosure of documents otherwise privileged from discovery under section 522(a)(2)(A) of the Act.[84] Prairie Group states that any pre-decisional document that is "adopted, formally or informally, as the agency position . . ." must be disclosed.[85]

(Footnote continued from previous page)
(1985). On October 9, 1985, the judge's Second Recommended Decision issued, (32 FERC ¶ 63,012), which found Watkins in violation of NGPA section 504, and Meyer Farms in violation of NGA section 7(b) and NGPA section 504.

[84]5 U.S.C. § 552(a)(2)(A) (1984) refers to "final opinions" of an agency and requires them to be made available to the public.

[85]Request by Prairie Oil Company, *et al.* for Rehearing of Opinion No. 239 at 34, *quoting* Coastal States Gas Corp. v. DOE, 617 F.2d 854, 866 (D.C. Cir. 1980).

Contrary to Prairie Group's assertions, the documents sought were neither "final opinions" nor "adopted" by the Commission in any sense of the term. What were sought are documents related to the preliminary investigation of respondents. These documents are covered by a number of privileges including the deliberative process privilege, attorney-client privilege, and work product privilege.

At the time the show cause order was issued, this Commission had neither formally nor informally taken a position regarding possible violations of federal law. The internal privileged documents of attorneys and other Staff which led to the show cause order cannot be deemed to have been "adopted" by the agency as an order. The show cause order fully apprised respondents of the scope of the inquiry regarding them, and set the matter for hearing. That order, Opinion No. 239, and other orders issued in this proceeding have been available to respondents and the public and fully conform to the requirements of the FOIA.

III. *The Commission orders:*

(1) The motions for stay of Opinion No. 239 are denied;

(2) The requests for rehearing of Opinion No. 239 are denied. By the Commission.

(S E A L)

Kenneth F. Plumb,

Secretary.

(3) 89-196

NO. ________

IN THE
SUPREME COURT OF THE UNITED STATES
OCTOBER TERM, 1988

RAILROAD COMMISSION OF TEXAS,
Petitioner

V.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

Appendix To Petition For Writ Of Certiorari To The United States Court Of Appeals For The Tenth Circuit

VOLUME 2

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121 p

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EXHIBIT D

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Stowers Oil & Gas Company, Docket No. GP84-23-000 *et al.*

RECOMMENDED DECISION
(January 16, 1985)

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I. APPEARANCES

Thomas K. Anson and *P.M. Schenkkan* for Anadarko Production Company and Pan Eastern Exploration Company.

Robert W. Clark, III, Maston C. Courtney and *D. Patrick Long* for Cabot Pipeline Corporation.

William M. Lange and *Nancy A. White* for Colorado Interstate Gas Company.

Thomas H. Burton for Conoco, Inc.

Norman A. Flaningam and *Karol Lyn Newman* for Consolidated Royalty Owners, Inc.

Philip R. Ehrenkranz, R. David Kitchen and *James L. Trump* for Dorchester Gas Producing Company.

Paul W. Fox and *Charles H. Shoneman* for Getty Oil Company.

Jody G. Sheets for Lucky Bird Petroleum.

Michael H. Loftin and *R.A. Wilson* for Meyers Farms, Inc.

J. Paul Douglas for Mobil Producing Texas and New Mexico, Inc.

Joseph Wells for Natural Gas Pipeline Company of America.

Patrick J. McCarthy and *Steve Stojic* for Northern Natural Gas Company.

Larry J. Laurent, W. Scott McCollough, Jim Mattox, and *David R. Richards* for the State of Texas.

Jerry D. Courtney, Ivan D. Hafley, Charles A. Moore, Robert W. Perdue, Daniel G. Shillito, and Michael K. Swan for Stowers Oil and Gas Company, et al.

Joe H. Foy and *Gail S. Gilman* for J. B. Watkins.

Nathan Fishkin, Robert Fleishman, Michael T. Mishkin and Steven Ross for the Federal Energy Regulatory Commission's Enforcement Staff.

Murray, Presiding Administrative Law Judge:

II. BACKGROUND

On February 15, 1984, this Commission ordered 37 oil well operators in the Panhandle West Gas Field in Texas (respondents) to show cause why they have not violated certain Federal laws (Show Cause Order, 26 FERC 61,207). Specifically the Commission ordered respondents to show that they are not violating and have not violated Section 7(b) of the Natural Gas Act (NGA) and Section 504 (a) (1) of the Natural Gas Policy Act of 1978 (NGPA) by producing and selling in intrastate commerce natural gas which was committed or dedicated to interstate commerce and\or charging and collecting prices in excess of the lawful maximum. The essence of the allegations is that respondents are producing and selling gas which is covered by a sales contract between non-respondent Dorchester Gas Producing Company (Dorchester) and Northern Natural Gas Company, Division of InterNorth, Inc. (Northern Natural) and which was dedicated to interstate commerce on June 7, 1954, long before any of respondents' well were drilled.

The respondents and the oil wells they operate are listed in Appendix A attached hereto. The parties agree that the well on the J.B. Watkins Bell B lease should be eliminated from the list since gas is not being sold from the lease.

This proceeding could have two phases. If in phase one the Commission finds that the alleged violations have occurred, phase two will consider the appropriate monetary remedies. I have held hearings and received briefs on the issues in phase one.

Numerous proceedings involving many of the same parties and related issues have been decided or are pending in the Texas courts and before the Texas Railroad Commission.

III. ISSUES

The issues are:

1. Whether 34 of the respondents, all except Komanche Oil & Gas, Stowers Oil & Gas, and J.B. Watkins, have sold and are selling in intrastate commerce gas previously dedicated to interstate commerce and at prices above the maximum allowed under Section 104 of the NGPA. Such actions would violate (1) section 7(B) of the NGA which requires that dedicated gas continue in interstate commerce until this Commission grants an abandonment application, unless NGPA Section 601 (a) (1) (B) has terminated this Commission's NGA jurisdiction, and (2) section 504 of the NGPA which requires that gas dedicated to interstate commerce and for which just and reasonable rates under the NGA were in effect on the day before the NGPA was enacted be sold at prices no higher than NGPA section 104 prices.

2. Whether Komanche Oil & Gas, Stowers Oil & Gas, and J.B. Watkins have sold and are selling gas previously dedicated to interstate commerce and for which just and reasonable rates under the NGA were in effect on the day before the NGPA was enacted at

prices above that allowed under Section 504 of the NGPA.

IV. FACTS

The applicable statutory provisions are as follows:

NGA Section 7: (b) No natural gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first hand and obtained after due hearing, and a finding by the commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

NGPA Section 104: (a) APPLICATION.-- In the case of natural gas committed or dedicated to interstate commerce on the day before the date of the enactment of the Act and for which a just and reasonable rate under the Natural Gas Act was in effect on such date for the sale of such natural gas, the maximum lawful price computed under subsection (b) shall apply to any first sale of such natural gas delivered during any month.

NGPA Section 504: (a) GENERAL RULE. --It shall be unlawful for any person--

(1) to sell natural gas at a first sale price in excess of any applicable maximum lawful price under this Act; or
(2) to otherwise violate any provision of this Act or any rule or order under this Act.

In 1935 the Texas Railroad Commission (Railroad Commission) announced that an area running in a southeasterly northwesterly direction, 124 miles long, averaging approximately 20 miles wide, containing 1,504,396 acres in Hartley, Moore, Hutchinson, Potter, Carson, Gray, and Wheeler Counties Texas, appeared to overlie the largest then known reserve of natural gas in the United States (Special Order Fixing Allowable Production of Sweet and Sour Natural Gas in the Panhandle District of Texas) (Exhibits 33 and 307, compare Tr. 402). The field, generally referred to as the Panhandle Field, lies on the buried Amarillo mountains, a remnant of the Wichita mountains which appear today at the earth's surface near Lawton, Oklahoma at an elevation of about 1,000 feet (Tr. 402, 422-423). Virgin pressure in wells drilled in the field was about 430-435 pounds per square inch gauge (psig) (Tr. 416-417). By 1984 the field had over 12,000 oil wells and about 4,500 gas wells and the reservoir pressure was 25 to 30 psig (Tr. 523-524, 1171).

As a general proposition, if oil and gas are present in porous rock, the oil will naturally accumulate in the lower portions of the formation. At a given depth, a flat formation will produce the same kind of hydrocarbon across the entire area under which the formation lies. Accordingly, where two wells are completed at the same depth intervals within a formation which has little or no structural relief, the two wells can be expected to produce the same kind of hydrocarbons (Exhibit 104 at 32).

Panhandle crude oil is a very dark green or green to brown, opaque liquid (Exhibit 92 at 8). It has as (American Petroleum Institute) API gravity of about 42 degrees, an average molecular weight of about 220, and an initial boiling point of about 130 degrees Fahrenheit (Exhibits 88 at 40-41 and 92 at 18, 20).

In the 1930's, the Railroad Commission established separate oil and gas fields in this geographic area. The oil fields carry a county designation, e.g. Panhandle (Carson) Oil Field and Panhandle (Gray) Oil field. Railroad Commission regulations provide 10 or 20-acre oil proration units in the Panhandle oil fields. The Railroad Commission designated the gas fields as the Panhandle West Gas field with 640 acre gas proration units and the panhandle East Gas Field with 160 acre gas proration units (Exhibits 307 at 6). While the proration unit of an oil well and a gas well can share the same surface area, the Railroad Commission established a division within the Wolfcamp Series (the dolomite, arkosic dolomite, limestone and granite wash formations) between the portion or the reservoir which was to be produced by oil wells, and the portion which was to be produced by gas wells (Exhibit 583 at 14; Exhibit 86).

The Railroad Commission has classified the Panhandle Field as a common reservoir, i.e. a pressure-connected unit (Tr. 1337-1339), and the portion of the reservoir from which the Dorchester wells produce only free gas as a non-associated has reservoir (Exhibit 264 at 50). Within the so-called "common reservoir" underlying the acreage which is the subject of this proceeding, there are distinct fields: the Panhandle West Gas Field, which consists of the portion of the reservoir lying above the gas-oil contact, and the Panhandle (Carson) and Panhandle (Gray) Oil Fields,

which consist of the portion of the reservoir lying below the gas-oil contact (Exhibit 583 at 14-19). The oil field beneath any given surface acreage within the Panhandle Field lies below the gas field (*ibid.* at 16).

The average depth of the producing formations in the Panhandle Field is about 2500 to 3000 feet (Tr. 415). Since 1933, the Railroad Commission has required all oil well operators in the state to determine the position of the gas-oil contact in each individual well bore and to perforate only below the gas-oil contact Exhibit 583) at 14, Tr. 3420). Statewide Rule 13 (b) (4) (B) (Exhibit 531 at 2) provides:

> (B) Isolation of Associated Gas Zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

The Railroad Commission has also issued rules specifically for the Panhandle fields. On October 17, 1933, the Railroad Commission adopted Circular 16-B, a field rule, which in part covered the Panhandle area including the Panhandle West Gas Field, the Panhandle East Gas Field, and the Panhandle County) Oil Fields. Circular 16-B, Division 2, Section II, Rule No. 3 provided that casings in gas wells in the Panhandle Field must be set and cemented not more than 25 feet above the part where the first show of gas is encountered in the lime formation (Exhibit 583 at 17) if said wells are to be produced from said formation. When wells are to be completed as oil wells at a depth below the lime gas, one string of casing must be set and cemented with sufficient cement to completely and

effectively seal off the gas formation from other formations; all casing must be cemented by the pump and plug method (ibid.). Rule No.3 means that all oil wells must have all their perforations only below the gas-oil contact point is determined by the operator in individual well bores, not by a general gas-oil contact for the entire reservoir (Exhibit 583 at 17, 19 and 21).

Dorchester has 35 gas wells located on the 21,284 acres in Carson and Gray Counties, Texas involved in this proceeding (sometimes referred to as the "subject acreage"). These Dorchester wells, drilled between 1934 and 1949, were almost all completed only in the brown dolomite portion of the geological formation (Exhibit 402 at 6-7; Tr. 284-86). The single exception appears to be Dorchester's No. 1 Warren which is perforated in the granite wash (Tr. 587-88; Exhibit 43). Since Dorchester acquired these wells in 1954 they have produced only hydrocarbons in the gaseous state (Exhibit 4 at 16-19). Dorchester sells the gas produced from these 35 wells to Northern Natural. As shown in the following table, in May 1984, production from 20 of these wells was committed or dedicated to interstate commerce on November 8, 1978 and as to which a just and reasonable price was in effect on that date, and production from 15 wells was priced at NGPA 108 levels applicable to stripper well gas (Exhibit 4 at 21).

DORCHESTER GAS PRODUCING COMPANY
PRORATION UNITS SUBJECT TO 2/15/84 SHOW CAUSE ORDER
WELL COMPLETION DATES AND
1983 PRODUCTION AND PRICING SUMMARY
(Exhibit 5)

Well Name	Completion Date	Current NGPA Category	Production MMBTU	Gross Receipts Value*	Average Price Per MMBTU
Beavers #1	2/17/45	108	5,872	$ 21,598.75	$3.68
Bednorz #1	6/09/34	108	8,078	29,479.98	3.65
Bell #1	12/29/37	108	13,452	39,830.04	2.96**
Bell #2	5/18/39	108	12,248	44,189.76	3.61
Bell #3	5/23/39	108	12,748	38,283.70	3.05**
Benedict #1	5/06/39	104 FG	23,321	10,771.96	.46
Bryan #1	12/01/36	104 FG	29,681	13,712.29	.46
Case #1	8/03/49	104 FG	78,635	36,395.69	.46
Chadwick #1	11/05/35	104 FG	22,073	10,235.12	.46
Cobb #1	4/21/36	108	15,190	55,220.49	3.64
Coffee #1	7/08/38	104 FG	67,582	31,222.17	.46
Durrett #1	9/30/38	104 FG	73,904	34,163.61	.46
Evans #1	8/23/39	108	36,858	133,100.56	3.61
Fields #1	3/31/36	104 FG	51,373	23,698.27	.46
Fields #2	12/15/36	104 FG	14,638	6,749.71	.46
Ginn #1	9/01/47	104 FG	29,424	13,644.11	.46
Haiduk #1	7/30/40	104 FG	43,790	20,232.37	.46

Kirney #1	6/03/48	104 FG	14,106	6,549.33	.46
Mathers #1	5/27/48	104 FG	32,551	15,054.09	.46
McBrayer #1	11/10/45	108	7,260	26,527.74	3.65
McConnell #4	8/27/34	108	6,588	24,060.34	3.65
Mongole #1	1/09/38	108	9,673	35,212.85	3.64
Osborne #2	8/23/49	108	16,270	59,623.01	3.66
Pickens #1	6/15/38	104 FG	33,521	15,509.31	.46
Pinnell #1	8/23/47	108	12,342	44,749.67	3.63
Pope #1	8/04/48	104 FG	28,088	13,097.54	.47
Sheridan #3	8/12/45	108	15,156	55,422.14	3.66
Vanderburg #1	8/18/47	108	8,138	29,577.72	3.63
Vaniman #1	9/11/39	104 FG	18,864	8,703.90	.46
Walker #1	8/28/39	104 FG	50,191	23,188.09	.46
Warren #1	8/13/38	104 FG	61,110	28,170.15	.46
White Deer Invest. #1	10/22/35	104 FG	28,036	12,938.70	.46
Wilson-Hart #1	5/20/38	108	10,908	39,945.87	3.62
Witter #1A	2/26/43	104 FG	39,033	18,030.02	.46
Witter #2	9/15/38	104 FG	63,202	29,223.17	.46
			993,904	$1,047,642.22	

1983 Weighted Average Price per MMBTU = $1.05

FOOTNOTE:
* Excludes tax reimbursement value.
** Both the Bell #1 and Bell #3 qualified for NGPA Sec. 108 effective February 17, 1983.

The Dorchester Chadwick No. 1 was completed for a time in both the brown dolomite and granite wash in 1935 and 1936 before it was plugged back and access to the granite was eliminated (Exhibit 4 at 19). Dorchester had a well about a mile outside the area covered by the Show Cause Order (Bobbit No. 1) which produced so much oil that it was reclassified as an oil well. Bednorz No. 1 on the Show Cause acreage and the Thompson well outside the subject acreage have had oil in the well bore (Tr. 292 1200-1233). Dorchester has at least one well on which it holds a Section 103 determination. Kinney No. 2 completed in 1981 was found to be necessary for effective and efficient drainage of the reservoir (Exhibit 4 at 14).

Dorchester's wells are all open-hole completions, i.e., the casing (a steel pipe 5"-8" in diameter) is set (or cemented in the well bore) above the stratum expected to be productive of hydrocarbons, and the portion of the well bore below the casing is exposed to the producing formation (Exhibit 104 at 25). For open hole completions, the completion interval is that portion of the hole at which depths the rock formation is exposed.

Respondents operate 196 wells on proration units which occupy the same surface area as the proration units assigned to Dorchester's 35 gas wells, i.e. the acreage subject to Cause Order (Exhibit 4 at 11). The Railroad Commission, based on information submitted by respondents, has classified all of respondents' wells as oil wells. Almost all of these wells were completed after November 9, 1987, the effective date for the NGPA. NGPA Section 103 allows prices for gas from "new onshore production wells" and Section 109 allows ceiling prices for new natural gas that does not fit into a designated category. Prices under both sections are substantially above the Section 104 price which covers gas committed or dedicated to interstate

commerce before the NGPA was enacted. Respondents sell almost all the gas from the wells named in the Show Cause Order to either Cabot Pipeline Corporation (Cabot), Getty Oil Company (Getty), Kerr McGee, or Northern Natural at Section 103 or Section 109 prices (See Staff's Initial Brief at 28, n. 15). The Railroad Commission has affirmatively determined respondent's well categories, and those determinations have become administratively final, 18 CFR § 275.202. According to Enforcement Staff and Dorchester, respondents are collecting Section 103 prices for all wells except ten wells for which they are collecting Section 109 prices (Enforcement Staff and Dorchester Initial Brief at 211-212).

Most of respondents' wells are perforated in the brown dolomite and the granite wash in a portion of the field where the brown dolomite lies in a high structural position, i.e. on top of the granite ridge that underlies the field (TR. 602). In most cases respondents' W-2 forms filed with the Railroad Commission do not show the perforations in the brown dolomite made after the initial completion in the granite wash. Most of the information about respondents' brown dolomite perforations was secured by discovery, in other litigation, or by stipulation in this proceeding. Meyer Farms testified its wells were completed only in the granite wash (Exhibit 476). Enforcement Staff and Dorchester's evidence would indicate that at least some of Meyer Farms Wells are perforated in the brown dolomite and above the gas-oil contact (Exhibit 104 at 233-240). The Producer Group named those respondents and their wells which they contend are not perforated in the brown dolomite (Exhibit 1A, attached as Appendix B to this decision). Enforcement Staff and Dorchester do not agree as to Komanche Oil & Gas Cobb No. 3 and 4, and they assert that the Wy-Vel Corp. Coffee No. 1 and Hodges No. 2

are perforated close to the bottom of the brown dolomite and fracturing has caused these wells to produce from the brown dolomite (Exhibit 104 at 54-55 and 118-119). A comparison of Appendix A and Appendix B shows that each respondent except Meyer Farms has at least one well perforated in the brown dolomite.

When a well is perforated, the completion interval or producing interval is that portion of the hole at which depths the perforations begin and end (Exhibit 104 at 28). Where the brown dolomite lies at the same depth continuously, the producing intervals of respondents' wells which are open in the brown dolomite overlap the producing intervals of the Dorchester wells since the latter are open from beneath where the casing is set down to the total well depth or plugged-back depth. An overlap may not occur where the wells are open in an area of the brown dolomite which shows very substantial structural relief.

Twenty-eight respondents (see Appendix C and Exhibit 582) operate gas processing units on their leases. These units operate at low temperature and extract liquids from natural gases (TR. 968). The result is a clear, water-white liquid which respondents call Panhandle light crude oil (Tr. 955, 958). Respondents count these liquids as oil in making the calculations and thus reduce their gas-oil ratios.

Well operators have traditionally had to apply to the Railroad Commission for a well classification. This requirement continues under the NGPA regulations, 18 CFR § 274.501. Wells are classified based on the phase behavior of the well's effluent at current reservoir conditions immediately outside the well bore in the formation, i.e. the gas-oil ratio at the "bottom of the hole" (Exhibit 583 at 35; Exhibit 92 at 4-5). This well

classification test is what is known as a recombined sample analysis. In the absence of a recombined sample analysis the Railroad Commission for many years has utilized what has been referred to as a "rule of thumb." If a well is submitted to the Commission with an American Society for Testing Materials (ASTM) distillation showing that the well produces a liquid hydrocarbon of 49-1/2 degrees API gravity or greater, with a surface ratio of 13,500 cubic feet of gas to one barrel of liquid hydrocarbon or greater and an initial boiling point of less than 120 degrees Fahrenheit, with 80 percent of that liquid vaporized at less than 520 degrees Fahrenheit and an end point less than 720 degrees Fahrenheit, with no evidence of cracking and at least 95 percent recovery, then the Commission will accept that well as a gas well in the absence of a protest. The reason for this rule of thumb is that a well with those characteristics at the surface would have a 100,000 to one gas-oil ratio or greater in the reservoir (Exhibit 583 at 39-40). For classification purposes, the volumes designated oil must be a hydrocarbon that is liquid in the reservoir, a liquid in the well bore, and a liquid at the surface (Exhibit 583 at 42). The process of classifying a well as an oil or gas well depends largely on the data the applicant submits. If the production results submitted to the Commission show a ratio of 100,000 cubic feet or gas or less to one barrel of oil, not to exceed 500,000 cubic feet of gas per day then the well in the Panhandle Field is classified as an oil well (Exhibit 402 at 10).

For the purposes of fixing "allowables," i.e. the volume of production permitted, the Railroad Commission classifies the Panhandle West Gas Field as a non-associated gas reservoir, even though the free gas phase overlies and is in contact with a black oil zone so that by accepted definitions it is an associated reservoir (Tr. 1138-1140, 3396).

The chronology of Dorchester's acquisition of leasehold rights, Northern's acquisition of gas purchase rights, and respondent's acquisition of oil rights is as follows:

1. Commencing in the mid 1920s, Lawrence Hagy, Donald Harrington and Stanley Marsh, an equal partnership, acquired approximately 49,000 acres of leasehold rights to oil and gas in Carson and Gray Counties, Texas. In the 1930s when the Railroad Commission initiated a 640-acre spacing requirement for gas wells the partnership had to consolidate its leases so as to satisfy the rules and its lease requirements. (Tr. 2740-2742). Most of the partnership gas wells were completed in the brown dolomite formation and produced dry gas (Exhibit 402 at 2-14; Tr. 2745).

2. Prior to 1937 the partnership could not sell its gas so it built the Cargray plant where it extracted natural gasoline an then vented the remaining gas (Tr. 2742-43). In 1937, Hagy, Harrington and Marsh contracted with Northern Natural to sell it natural gas from wells on this acreage. The parties entered a replacement contract in 1947. Eight of Dorchester's gas wells are on the land covered by the 1937 contract and 27 of its wells are on the land covered by the 1947 replacement contract (Exhibit 4 at 6). In the late 1940s, Panoma Corporation (Panoma) organized by Donald Harrington acquired the leasehold rights held by the Hagy, Harrington and Marsh partnership. Panoma held record title to the oil rights for convenience, beneficial ownership stayed with the partners (Exhibit 402 at 14; Tr. 2745). The assignment by Lawrence Hagy to Panoma signed October 1, 1949 specifies the assignment of all the assignor's rights, title and interest in specified oil, gas and mineral leases and leasehold estates but retains in the assignor an

overriding royalty on all gas produced and marketed from the assigned properties (Exhibit 406). Or October 1, 1949, Northern Natural's gas purchase contract was amended to substitute Panoma Corporation as seller and to add acreage so that on this date gas from all the acreage which is the subject of this proceeding was contractually committed to Northern Natural (Exhibit 4 at 6).

3. In a letter dated October 10, 1949, Panoma agreed that for convenience record title to oil rights under the oil and gas leasehold conveyed to Panoma shall remain in Panoma but that Lawrence R. Hagy was beneficial owner of an undivided one-third interest in and to the oil and oil rights under the leaseholds conveyed to Panoma by the assignments of October 1, 1949 (Exhibit 407). This letter was not recorded. Panoma assigned the oil and oil rights down to sea level to Lawrence R. Hagy in 1953 (Exhibit 407 at 14; Exhibits 407, 408, 409 and 410).

4. In approximately 1949 Don Harrington and Lawrence Hagy sold seven oil wells they had drilled in Sections 184 and 207, Block B-2 H&GN Ry Co. Survey, Gray County, Texas along with other underdeveloped oil acreage to Service Drilling Company (Exhibit 402 at 7). Prior to drilling these oil wells, Hagy, Harrington and Marsh had drilled a gas well on each of these two sections (Exhibit 402 at 8). Service Drilling drilled more oil wells on this land.

5. On July 1, 1952, Panoma and Northern Natural entered into a replacement contract which added more acreage in Carson and Gray Counties for a total of 49,944 acres (Exhibit 6). An amendment to the contract made February 12, 1954 did not affect the terms of the 1952 contract as it relates to the subject acreage (Exhibit 4 at 7).

The 1952 gas purchase contract between Panoma and Northern Natural contained the following provisions (Exhibit 6):

ARTICLE I

GAS TO BE DELIVERED AND PURCHASED

> *Section 1. Gas to be Delivered and Purchased.* Subject to the terms and conditions of this contract, Seller agrees to sell and deliver to Northern hereunder, and Northern agrees to purchase and receive from Seller all of the natural gas produced from the wells now drilled and hereafter to be drilled on the acreage described in Exhibits 'A' and 'B', or on acreage substituted therefor or added thereto, as herein provided.

ARTICLE IX

DEDICATION OF GAS RIGHTS AND WELLS

> Subject to Seller's reservation of the natural gasoline and other liquefiable hydrocarbons to the extent set forth in Section 1 of Article VII, Seller agrees that all of its gas rights in the gas lands and leases covering the acreage in the White Deer and Alanreed Areas, or acreage substituted therefor, or added thereto together with all wells now drilled and hereafter to be drilled on such acreage, which are productive of gas in commercial quantities, are hereby exclusively dedicated and devoted to the fulfillment and performance of this agreement ....

The contract contains no depth limitations, no exclusion of particular formations, no restrictions as to any particular type of natural gas, and no restriction as to natural gas from any particular type of well (Exhibit 4 at 9).

Appendix C of the Initial Brief of the Producer Group (represented most of the respondents) lists certain wells located on oil and oil right leaseholds on the subject acreage which it claims Panoma never held.

6. On June 7, 1954, the Commission began regulating natural gas sales in interstate commerce for resale by independent producers (*Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954)). On this date Panoma was selling Northern Natural gas from 93 wells located on the 49,944 acres dedicated to Northern Natural by the 1952 contract as amended, including gas from 35 wells on the subject 21,284 acres (Exhibit 4 at 10). Neither Hagy, Harrington and Marsh nor Panoma sold Northern Natural any casinghead gas from this acreage on or prior to June 7, 1954 (Exhibit 402 at 17).

7. On July 1, 1954, Panoma was dissolved and its shareholders (D.D. Harrington, *et al.*) received the assets and transferred to Nalam Corporation "the gas and mineral (other than oil) in and that may be produced from, the producing horizons which are situated in whole or in part above sea level. ..." (Exhibit 10 at 60).

8. By instruments dated July 1, 1954, D.D. Harrington, *et al.* conveyed to Nalam Corporation (Nalam) which simultaneously conveyed to Dorchester the following (Exhibit 7):

PART II OF EXHIBIT A

CARSON & GRAY COUNTIES, TEXAS -- GAS LEASEHOLDS

> The leasehold estates created by or existing under and by virtue of those certain oil, gas and mineral leases hereinafter described covering lands in Carson and Gray Counties, Texas hereinafter described, insofar as said leasehold estates cover the gas and mineral (other than oil) leasehold rights in, and the title to gas and other minerals (other than oil) in and that may be produced from, the producing horizons which are situated in whole or in part above sea level; but subject however to the exceptions, limitations and burdens hereinafter specified and to the express exception of all rights, titles and interests in and to said leasehold insofar as said leasehold estates relate to oil or oil rights.

The Nalam conveyance to Dorchester stated (Exhibit 11 at 61):

> Further, said leasehold estates are subject to the terms and provisions of (a) that certain Natural Gas Purchase Contract dated July 1, 1952, between Northern Natural Gas Company, as Buyer, and Panoma Corporation, as Seller, as amended by Amendatory Agreement dated February 12, 1954.

9. Between 1954 and 1984, the shareholder of Panoma (D.D. Harrington, *et al.*) and Lawrence Hagy consolidated their interests in oil and oil rights above

and below sea level. Since 1979 Hagy, Sybil Harrington and the Harrington Foundation entered into farmout agreements and assignments with most of the respondents (Exhibits 411-419). These farmout agreements typically provide (Exhibit 17 at 4):

> 4. *Exclusions*. It is expressly provided that this Farmout Agreement does not cover or apply to dry gas rights and under the lands described on Exhibit "A" and that Farmees shall set and cement the casing in all wells drilled hereunder in such a manner as to prevent gas well gas from entering the oil zones. In no event shall any dry gas produced from gas zones be produced with the oil or casinghead gas produced by Farmees.

10. Respondents then contracted to sell their gas to Cabot, Getty, Kerr McGee and Northern Natural.

Dorchester applied to the Federal Power Commission for a certificate of public convenience and necessity in November 1954 for the sale of gas to Northern Natural under the 1952 contract (Exhibit 12). The contract was an exhibit to the application (Exhibit 519 at 6). On February 6, 1956, the Commission in Docket No. G-5925 issued Dorchester a certificate pursuant to Section 7 of the Natural Gas Act authorizing it to sell natural gas from the Panhandle Field, Carson and Gray Counties, Texas to Northern Natural (Exhibit 13). The certificate referred to the application and did not describe the gas dedicated by Dorchester.

As noted above Dorchester has a leasehold interest in the 49,944 acres from which Panoma committed gas sales to Northern in 1952. The show

cause order covers only part of the acreage. It defines as the subject acreage the 21,444 acres comprising 35 Dorchester proration units. See Exhibit 4 at 12-16 for an explanation of how this acreage was reduced to 21,284 acres.

Within the Panhandle Field the geological formations in order of appearance from the top are base massive anhydrite, brown dolomite, arkosic shale, arkosic dolomite/limestone, granite wash, jackson member and granite basement (Exhibit 74). Hydrocarbons in the gaseous or vapor state are usually found in the brown dolomite, a carbonite type of rock, which extends over the entire Panhandle Field without any significant break in continuity (Exhibit 73 at 9; Tr. 407). It is possible in a single field for the brown dolomite, depending on where it is located structurally, to be productive (low lying) or non-productive (high lying) of hydrocarbons that are in liquid form in the reservoir, in the well bore and at the surface, i.e. crude oil (Exhibit 264 at 33; Tr. 694-695). Production of just gas from the brown dolomite would indicate that the production source was above the gas-oil contact (Tr. 558). Structural areas that would be productive of gas or oil in the field (Tr. 683). In the area immediately to the northeast of the subject acreage, a traditional oil producing area, the brown dolomite dips considerably and lies 300 to 750 feet below its typical position under the Dorchester acreage (Exhibit 264 at 3-10).

Exhibit 75 shows that northeast of the subject acreage, in an area known locally as the "South Pampa" oil field, the top of the brown dolomite appears 750 feet lower than the top of the brown dolomite in the Dorchester Bell No. 1 well (Exhibit 264 at 4). Similarly there is a structural dip of about 320 feet running west to east from the Harlow Beavers No. 3 well to the Texaco Jackson No. 14 well (Exhibits 73 at 6, 74). The

entire field, not just the subject acreage, dips off on either side with much more structural relief than is found in the subject area (Tr. 695).

A 1935 article about the field's geology noted that (Exhibit 405):

> The dolomite is the most consistent producing formation in the Panhandle, producing gas over almost all of the higher part of the structure and oil on the north flank. It is usually referred to a the "Big Gas" horizon.
>
> * * *
>
> The granite wash ... produces gas on the higher parts of the structure and both gas and oil on the flanks. As a producing zone it is very erratic, but under favorable conditions in extremely prolific.
>
> * * *
>
> Gas is found in all of the producing formations where present on the higher parts of the regional structure, oil being present on the north flank and maintaining a general level between sea level and 200 feet above.

The Texas Natural Resources Code defines casinghead gas as "any gas or vapor indigenous to an oil stratum and produced from the stratum with oil," and the Railroad Commission has adopted this definition in its statewide rules. (Tex. Nat. Res. Code. Ann. § 86.002(10) (Vernon 1978)' Title 16, Texas Administrative Code, Section 3.69 Definitions, Railroad

Commission Rule 051.02.02.079). In various annual reports the Railroad Commission has talked about casinghead gas as gas produced from an oil well.

V. ARGUMENT

Enforcement Staff and Dorchester view this case as revealing only the tip of the iceberg or a widespread practice where parties, under the guise of drilling new oil wells, transform old (relatively cheap) dedicated natural gas into new (high cost) undedicated gas. Dorchester, Enforcement Staff, and Northern Natural contend that the 34 respondents have and are appropriating natural gas that is "dedicated" to interstate commerce, and this appropriation is illegal because there has been no compliance with the abandonment provision of the Natural Gas Act. It is undisputed that Dorchester's reserves under discussion were, at the time Dorchester acquired them, already developed and producing, and were dedicated to interstate commerce. *Dorchester Gas Producing Co. v. FERC*, 571 F.2d 823 at 825 (5th Cir. 1978). The issue here is what was dedicated.

Dorchester and Enforcement Staff contend that all natural gas (including casinghead gas) underlying the 21,284 acres which is the subject of the Show Cause Order was dedicated to interstate commerce on June 7, 1954. Dorchester and Enforcement Staff reason that on this date when the Commission began regulating interstate gas sales for resale by independent producers, all gas under this land was "dedicated" to Northern Natural because the 1952 gas sales contract between Panoma and Northern Natural was in effect which covered all gas, citing the portions of Article I and Article IX quoted above, and Panoma was making gas deliveries to Northern Natural from this acreage (Exhibit 4 at 10). Enforcement Staff and Dorchester

note that Panoma's 1952 contract with Northern Natural occurred before Panoma's 1953 assignment of oil and oil rights to Lawrence Hagy.

Section 7 of the Natural Gas Act does not use the term dedication; however, the term is commonly used to describe the service obligation which attaches as a matter of law to natural gas which is sold in interstate commerce for resale. Enforcement Staff argues that a contract or certificate is not necessary to dedicate natural as to interstate commerce (Exhibit 603 at 7): "The commencement of deliveries of natural gas in interstate commerce is the act which, standing alone, dedicates natural gas from those properties and makes the natural gas subject to the Commission's authority." *Mountain Fuel Supply Co. and Wexpro Co.*, 24 FERC ¶ 61,120 at 61,293, *rehearing denied*, 24 FERC ¶ 61,321 (1983); *see also J. M. Huber Corp. v. FPC*, 236 F.2d 550, 556-558 (3rd Cir. 1956), *cert. denied*, 352 U.S. 971 (1957); *Tenneco Exploration, Ltd. v. FERC*, 649 F.2d 376, 379-380 (5th Cir. 1981). According to Dorchester and Enforcement Staff, because Northern Natural was purchasing gas from this acreage on June 7, 1954 under a contract which committed to the performance of that contact "all natural gas" produced from all present and future wells located on this acreage, all gas produced from the acreage, including casinghead gas, is dedicated to interstate commerce under the Natural Gas Act (Exhibit 603 at 13-14).

The parties aligned with Enforcement Staff and Dorchester maintain that the Commission has jurisdiction despite the fact that respondents hold incentive pricing determinations under Sections 103 and 109 of the NGPA because:

(Section 503(d) NGPA). These parties claim that the Railroad Commission after their applications were submitted, make additional completions in the brown dolomite above the gas-oil contact and that some respondents relied on refrigeration units to achieve the gas-oil ratios shown on their applications (Reply Brief of Indicated Intervenors, p. 7-8).

2. The Section 103 determinations apply only to respondents' gas production from below the gas-oil contact (true casinghead gas). This is because a "new onshore production well" (NGPA Section 103) cannot be within a proration unit which was in existence at the time the surface drilling of the new well began and which was applicable to the reservoir from which natural gas from such new well is produced. The NGPA defines a proration unit as any portion of a reservoir which will be effectively and efficiently drained by a single well (Section 2(8)). Enforcement Staff and Dorchester conclude that the common reservoir underlying the Panhandle West Gas Field fits the NGPA definition and the boundary of that portion effectively and efficiently drained by an oil well is defined by the gas-oil contact (Initial Brief at 212-215).

Colorado Interstate Gas Company is the only party which agrees with Staff and Dorchester that all gas underlying the land in question was dedicated to interstate commerce on June 7, 1954. Anadarko Production Company, Conoco, Inc., Mobil Producing Texas & New Mexico, Inc., Natural Gas Pipeline Company of America, Northern Natural, Pan Eastern Exploration Company, and Phillips Petroleum Company support Enforcement Staff and Dorchester's alternative position that respondents are violating federal laws because the 1952 contract dedicated to interstate commerce all gas except casinghead gas and respondents' production is not casinghead gas because

it is not gas that is indigenous to an oil stratum and produced from the stratum with oil. These parties contend that almost all the gas produced by respondents is from the brown dolomite formation which is not commercially productive of crude oil as encountered by respondents' wells. This contention is supported by testimony from employees or former employees of Conoco and Dorchester (Exhibits 289-291; Exhibits 4-24) but mainly by an in-dept study of the subject acreage by three consultants--a geologist, an expert in reservoir fluid analysis, and a petroleum reservoir engineer. These experts sponsored by Dorchester and Enforcement Staff gave testimony on 16 study area each containing one or more proration units for 35 Dorchester wells. The study areas were selected so as to include all wells with gas production which might affect production from the Dorchester gas well. The selection criteria for inclusion within a study area included a well's distance from the Dorchester well, its production characteristics, and its proximity to other Dorchester proration units. Adjacent oil wells with no discernible effect on Dorchester gas production were included within some study areas for comparison purposes (Tr. 20-21, 1468-1469, 1501-2). Some of the study areas included acreage which is not the subject of the show cause order (Exhibit 108 at 20; Exhibit 34; Tr. 1333).

The experts did the following:

1. The geologist, with the expert in reservoir engineering, prepared geologic structural cross sections for each study area, i.e. illustrations of the earth using a common datum point of 600 feet above sea level, displaying the wellbore holes of Dorchester's and respondents' wells in a view which is perpendicular to the surface of the ground, to show the wells' completion intervals and relative depth locations of the different

subsurface geologic formations (Exhibits 35-71); Tr. 458-459, 537, 1312-1313). This geologist studied well data sheets on Dorchester wells, and electric logs for respondents' wells, and made correlations between the well logs, determining formation tops and bases, and then determining the structural position of the brown dolomite marker and the granite wash marker (Exhibit 32 at 9-10; Tr. 454, 592). He concluded that from the standpoint of hydrocarbon production, there are two significant and distinct lithological formations encountered by the wells situated on the acreage which is the subject of this proceeding: the brown dolomite formation and the granite wash formation. The granite wash formation is deposited irregularly along the peaks and valleys of the buried granite ridge and exhibits great variation in rock composition both laterally and vertically (Exhibit 73 at 9). The shallower brown dolomite formation is comprised of porous rock material. This formation is of fairly uniform thickness as it underlies this acreage and extends over the entire Panhandle Field without any significant break in continuity. The brown dolomite formation is encountered in a relatively high structural position in all study areas except study areas 2, 11 and 12 where the brown dolomite formation experiences varying degrees of structural dip (Exhibit 32 at 51; Exhibit 73 at 11). Significant structural relief, a 300 foot drop, exists in study area 11 (Section 183 of Block B-2) (Tr. 682). The geologist has put the gas-oil contact in Section 94, Block B-2 H&GN Railroad Survey which is partially in Study Area 2, where the brown dolomite is the lowest of all the study areas, at a subsea depth of approximately 183 to 195 feet: the highest known oil was at 195 feet above sea level and lowest known gas was at 183 feet above sea level (Exhibit 73 at 7-9; Tr. 1262). This witness found that the gas-oil ratios for wells in the study areas perforated only below the gas-

oil contact were below 1,000 cubic feet of gas to one barrel of oil (Tr. 574).

2. The expert in reservoir fluid analysis tested 60 wells in September 1983 and April 1984 on 20 leases held by 12 respondents and Phillips Petroleum Company (Exhibit 88 at 6). Respondents did not voluntarily cooperate in many of the tests and they were done under court order (Tr. 919-920). The operators classify all these wells as oil wells. Eighteen of the leases had gas processing units, i.e. small on-lease facilities used to condense or manufacture natural gas liquids from a gas stream (Exhibit 88 at 5-6). The expert monitored natural gas and liquid production from each lease for approximately 48 hours. Measurements were taken periodically--of gas from the gas sales meter and for liquid from the on-lease stock tank. The ratio of surface gas to oil production was calculated from these data, adjusted to standard conditions of temperature and pressure and reported in standard cubic feet of gas per barrel of oil. Gas samples from the flowline (the pipeline that gathers production from all the wells on the lease) and stock-tank liquids and wellhead liquids were then taken and subjected to the following laboratory tests (Exhibit 88):

Liquids:

--ASTM D-86 distillation test where liquid is heated and vapor collected. This test determines the physical characteristics of the liquid (initial and end boiling points, percent distilled at any temperature).

--"fingerprint test" determines the relative quantities of various heavy (large number of carbon atoms) hydrocarbon components of the liquid which are not affected by weathering or handling techniques.

Gas and Liquids:

--hydrocarbon composition analyses which focus on light hydrocarbons. Used to determine the individual characteristics of hydrocarbons in a system.

--phase equilibrium tests were samples taken at the surface are recombined at reservoir pressure and temperature to determine the phase in which these samples existed in the reservoir, and whether the samples were in phase equilibrium when produced.

By the laws of physics, at higher pressure (in the reservoir) a certain amount of material in the gas phase will be driven into the liquid phase thus reducing the volume of gaseous material. The result is that if oil and gas are produced from the same porous rock the gas-oil ratio at the surface (at standard conditions) should be greater than the gas-oil ratio in the reservoir. If the gas-oil ratio at the surface is less than the gas-oil ratio in the reservoir, at reservoir conditions (22.4 psig and 99 degrees Fahrenheit) as recreated in the laboratory, then the gas and oil were not in phase equilibrium when produced and thus were not produced from the same porous rock (Exhibit 88 at 16-17, 33). The following test results are for the 18 tested leases that have gas processing units (Exhibit 88 at 61-62):

SUMMARY OF PHASE EQUILIBRIUM TESTS

Lease	Surface Recombination GOR	Reservoir GOR
Almac Big Bull	42,012	95,300
Aspen Chadwick	62,741	1,832,044
Aspen Jones	56,494	683,577
Aspen Warnick	60,498	901,424
Dahalo Vanderburg	61,464	442,543
3-W Tieman	71,323	520,661
Vanderburg Expl.Sandy	36,594	251,454
Vanderburg Prod. Vanderburg	49,573	541,996
Wy-Vel Dennis	68,480	1,705,154
Energy-Agri Henry	66,092	1,764,669
Energy-Agri Money	37,155	347,768
Energy-Agri Peeler	43,185	867,017
Magnet Dania	37,607	597,955
Raven Martha	68,516	842,751
Tri-Ex Culbertson	81,755	1,602,407
Tri-Ex Hayes Trust	60,292	783,798
Tumble Weed Haiduk	77,127	879,246
Wy-Vel Coffee	32,038	687,227

By Contrast the results for the two leases without gas processing units are as follows (Exhibit 90 at 11 and 18):

Lease	Surface Recombination GOR	Reservoir GOR
Raven Energy Jeanne	22,642	26,362
*Phillips Thornburg No. 1	202	159

* Not a respondent well but located on Dorchester's Pickens No. 1 proration unit on which four respondent wells are situated.

The expert in reservoir fluid analysis concluded:

> For every lease tested, the reservoir gas-oil ratios of the recombined samples were significantly higher than the produced gas-oil ratios measured at the surface during the test period. ... [W]hen the recombined samples were subjected to the increased pressure encountered in the reservoir, the volume of gas, and thus the gas-oil ratio of these recombined samples, should have been lower than that measured at the surface if the gas and liquid samples were in phase equilibrium. As shown on the above chart, it is clear that for all the leases tested, the reservoir gas-oil ratios of the recombined samples were extraordinarily high compared to the produced gas-oil ratios.
>
> Based on the level of the gas-oil ratios, it is my conclusion that an insignificant amount of oil was produced from any lease. The product in the stock tanks was principally the liquid condensed or manufactured by the on-lease gas processing units.
>
> From these results--the trends of data from the ASTM distillation tests and the hydrocarbon analyses of all samples--it is my opinion that the gas produced from these leases was not in phase equilibrium with the oil, if any, produced from these leases. Therefore, the oil and gas were not produced together from the same porous rock.

3. The third expert, who specializes in petroleum reservoir engineering, used the efforts of the other two in his analysis. He sponsored phase diagrams on the production of numerous Panhandle field wells. A phase diagram is a graph showing whether a sample mixture of hydrocarbons exists as a liquid, a gas, or as two phases in equilibrium, at any specified condition of temperature and pressure (Exhibit 104 at 7-13). The third expert used samples gathered by the second expert. In each case except the Raven Jeanne and Phillips Thornburg leases (Exhibit 109 at 5) these were gas samples taken before the gas enters the gas processing unit, not recombined gas oil samples (Tr. 1165-1168). For each diagram, the dew point and bubble point for the particular sample was plotted against temperature and pressure and then compared with current estimated reservoir pressure and temperature conditions (25 to 30 psig and 90 to 105 degrees Fahrenheit): if reservoir conditions appear on the diagram between the dew point line and the bubble point line, the conditions appear to the right of the dew point line it is a gas; and if reservoir conditions appear to the left of the bubble point line it is a liquid. The expert determine the dew point and bubble point values using the hydrocarbon compositional analyses of the particular well samples and a general formula (modified Soave-Redlich-Kwong equation of state) (Exhibit 104 at 10; see description at Tr. 1171-1173).

The phase diagrams show:

> Five diagrams from samples from four Dorchester wells (Osborne No. 2, Pinnell No. 1, Williams No. 1 and Jendrusch No. 1)--production in gas phase in the reservoir and at the surface (Exhibit 104 at 12-13, Exhibit 105).

J.B. Watkins Bell No. 1--phase behavoir of the gas similar to phase behavoir of Dorchester's gas wells therefore production was not in phase equilibrium in the reservoir. If liquid hydrocarbons were in phase equilibrium in the reservoir, phase diagram would resemble that of Phillips Thornburg No. 1 (Exhibit 109). Sample used for this diagram was not taken by the second expert like the others, it was a sample taken in August 1978 which J.B. Watkins transmitted to Phillips, who transmitted it to Northern Natural, who transmitted it to Enforcement Staff (Exhibits 104 at 13-14; 106 and Tr. 1421-1432).

18 respondent wells (Exhibit 104 at 14-15; Exhibits 107 and 108)-- production at inlet of gas processing units was gas in the reservoir.

Raven Jeanne lease and Phillips Petroleum Thornburg No. 1 well--two gas samples from each lease indicate material was gas in the reservoir and at the surface. Recombined flowline (wellhead) sample and stock tank sample shows the two materials were in equilibrium, but the shape of phase diagrams indicates that the Thornburg No. 1 to be typical of a crude oil well with significant liquid volumes at reservoir conditions, and the Jeanne lease has mostly gas and little liquid indicating that the gas and liquid phase were not in equilibrium in the reservoir, i.e., did not flow together from same porous rock. (Exhibit 104 at 15-17; Exhibit 109; Tr. 1173-1176)

The expert concluded that the phase diagram for the Jeanne lease would be representative of the respondent lease situated in a structurally high area of the brown dolomite formation with wells completed in the brown dolomite and granite wash formations, which has a high gas-oil ratio and no gas processing unit. Based on the "virtually identical" phase diagram for Dorchester's five wells and respondents' 18 wells, the expert believes that gas produced from leases with a gas processing unit is not in phase equilibrium with any crude oil produced from the lease (Exhibit 104 at 19-20).

The second part of the third expert's presentation showed by study area:

1. A graph of each Dorchester well's shut-in pressure plotted against its cumulative gas production from 1966 through April 1984 and a description of any shifts in the trend of the curve (Tr. 1501).

2. Completion intervals of all respondents' wells and Dorchester wells.

3. Production information including gas-oil ratios for respondents' leases.

This evidence is summarized in Appendix C.

This expert's analysis caused him to opine as follows about the gas from wells in the study areas (Exhibit 104 at 275-276):

> ...I conclude that almost all of the gas produced by respondent wells situated on the surface acreage of proration units assigned to Dorchester gas wells is not casinghead gas. It is not casinghead gas

> because it is not produced with oil from an oil-bearing formation. Rather, the gas has been and is being produced from the gas-bearing formation underlying Dorchester's acreage, in which formation the vast majority [of] respondents' wells have been perforated at the level of the Dorchester's producing interval. Accordingly, I conclude that the gas produced by respondent oil wells is the same gas that otherwise would be produced by Dorchester gas wells from the same formation from which the Dorchester gas wells have been effectively and efficiently draining gas for nearly 40 years.

The expert based his conclusion that respondents' gas production is being produced from the gas-bearing portion of the brown dolomite on Dorchester's production records, the geological evidence, the phase behavior information, the well completion records, as well as the completion and production records of other wells in the study areas (Tr. 1093).

The Stowers Oil and Gas Company, *et al.*, (the Producer Group) representing all respondents except Meyer Farms and J.B. Watkins, argues that Dorchester and Enforcement Staff have not proven their case either on the law or on the facts. The Producer Group sponsored testimony from numerous respondents and several experts. Much of this testimony entered the record without any requests for cross-examination (Exhibits 533 through 547 and 549 through 580). Respondents stressed that the Railroad Commission's District Supervisor assigned to the Panhandle Field told them it was permissible to complete an oil well from the top of the brown dolomite to the base of the

granite wash provided the resulting gas-oil ratio was less than 100,000 cubic feet of gas to one barrel of oil (Tr. 311-313). Many respondents recalled seeing oil shows in rock samples or cuttings and either seeing or hearing about oil production from the brown dolomite in the West Panhandle Field. The experts (Exhibits 314-345, 352-366, 402-403, 466-471, 473-475, 519, 520-527) opined that Panoma's assignments in 1953 of oil and oil rights to a party other than the owner of the gas rights suggests that the term "gas rights" in the 1952 contract did not include the production of casinghead gas, and that respondents' production was true casinghead gas because oil and gas are spread throughout all the formations due to oil vaporization and other reasons. To demonstrate that vaporization has occurred, the Producer Group's expert calculated the behavoir of the vapor specific gravities as they would change in response to pressure reduction in reservoir using the amount of gas and oil produced from each tract, the history of pressure decline of the reservoir in the tract, the specific gravity of the produced gas, and an estimate of the composition of the oil and gas phases as they existed under the tract before production began. The expert found that as the reservoir pressure declines, oil in the reservoir is vaporized into gas, and the specific gravity of the augmented gas increases. The expert concluded that gas produced on the Dorchester leases contains significant amounts of vaporized crude oil components (Exhibit 352 at 23).

The Producer Group's position may be summarized in two parts:

Part One: a) Because the NGA does not apply "...to the production or gathering of natural gas" (Section 1(b)) the Commission has no NGA jurisdiction over the acts and practices asserted in the Show Cause

Order. That is, the Commission has no jurisdiction to decide, determine or regulate matters involving the physical activities, properties and facilities of the production of natural gas.

b) Further, the Producer Group alleges that any NGA jurisdiction the Commission may have had over the acts and practices of respondents has been removed by operation of Section 601(a)(1)(B) of the NGPA: Once respondents obtained final Section 103 well category determinations under the NGPA abandonment permission was thereby obviated.

c) The Producer Group contends this Commission should not decide issues that involve the interpretation and construction of the Texas Natural Resources Code and the interpretation and application of the rules and regulations of the Railroad Commission; instead the Commission should defer to the State of Texas, its courts and the state regulatory agency having the jurisdiction and competence to make those determinations. Alternatively, this Commission should invoke the provisions of Section 17 of the NGA and convene a joint board with the State of Texas to decide these material Texas law questions.

Part Two: a) Even assuming the Commission has jurisdiction, the Producer Group argues that the overwhelming weight and preponderance of the credible evidence establish that the brown dolomite formation produces oil and not only gas.

b) Since all of respondents' wells have been properly and finally classified as oil wells, it follows from Railroad Commission regulations that all gas production from these wells is casinghead gas and none of it is "dry gas". Accordingly, respondents are not as alleged in the Show Cause Order, engaged in an

unlawful diversion of "dry gas" dedicated to interstate commerce nor are respondents producing and selling "dry gas" subject to a maximum lawful price under Section 104 of the NGPA.

The Producer Group's position is that all gas produced from any oil well is casinghead gas, and that attempts by Enforcement Staff and Dorchester to refine or alter this definition fall outside all Texas statutes and Texas regulatory classification (Tex. Nat. Res. Code Ann. § 86.002(5) (Vernon 1978)). The Producer Group argues that the Railroad Commission has recognized and relied on a 1940 Texas Attorney General's Opinion that states (Exhibit 326 at 4):

> In view of the above considerations, we conclude that the term 'casinghead gas' applies to all gas produced from any 'oil well' as defined in Subsection (e), Section 2, Article 6008,...

The Producer Group contends it is clear from this, that casinghead gas is all gas produced from any oil well.

The Producer Group maintains that the Texas courts construe the term stratum to be synonomous with reservoir. *Bens-Stoddard v. Aluminum Company of America,* 368 S.W. 2d 94 (Tex. 1963); *Railroad Commission v. Shell Oil Company,* 380 S.W. 2d 556 (Tex. 1964); and *Bolton v. Coats,* 533 S.W.2d 914 (Tex. 1975). Thus, all gas produced with oil from the common reservoir is produced from the same stratum as the oil. Moreover, the definition of an oil well under Texas law is simply a well that produces one barrel or more of oil to each 100,000 cubic feet of gas (Tex. Nat. Res. Code Ann. 86002(5) (Vernon 1978)). The Producer Group notes that this definition says nothing about the gas/oil

contact, but clearly implies that such an oil well can produce from the gas cap area above the oil (Item-by-Reference M, Legislative History of Texas, House Bill 266, Sections 2(d) and 2(e)). The Producer Group points out that the expert on Railroad Commission regulation sponsored by Dorchester and Enforcement Staff agreed it would be impossible for an oil well to produce only so-called "true" casinghead gas at gas-oil ratios of up to 100,000 cubic feet per barrel (Exhibit 596 and 597; Tr. 3596-97); thus gas cap gas produced by an oil well is properly considered casinghead gas. In support of its position, the Producer Group cites that expert's opinion that he would consider one of the J. B. Watkins wells producing at a gas-oil ratio of 94,444 to 1 an oil well and the gas it produced as casinghead gas (Tr. 3662) even though the gas was gas cap gas caused by the gas cap moving down in the well bore (Tr. 3660-61).

Turning to Enforcement Staff and Dorchester's argument that gas is not casinghead gas unless it is produced from a properly completed oil well, i.e. below the gas-oil contact, the Producer Group contends that the Texas statute and Railroad Commission rules and regulations contain no such requirement, and the only basis for the position of Enforcement Staff Dorchester is the opinion of the state regulatory expert who did not say gas produced from such a well was not was not casinghead gas, but only that he did not believe that a well perforated above and below the gas-oil contact (though they argue that there is no gas-oil contact requirement) and produces at a ratio of less than 100,000 cubic feet of gas per barrel of oil, that well is clearly an oil well as defined in both the Texas statute and Railroad Commission rules. The Producer Group ridicules the theory of Enforcement Staff and Dorchester as creating, in this situation, a new well category of illegal wells. The Producer Group argues that under the Texas regulatory scheme, a well must

be classified an oil well *or* a gas well regardless of the manner in which it is completed and operated. The Producer Group notes that, contrary to Enforcement Staff and Dorchester's position, the regulatory expert agreed that the Railroad Commission's annual reports are based on the state attorney general's construction of the Texas statute (Tr. 3547-3550; Exhibit 326). The Producer Group takes Enforcement Staff and Dorchester's position to mean that the Railroad Commission has carried on an unlawful gas classification system since 1952, blatantly publishing such unlawful practices every year to both the Governor and the people of Texas.

The Producer Group dismisses comments about respondents' use of gas processing or liquid extraction units as a strawman because the Show Cause Order makes no mention of such units, and "the propriety of the use of refrigeration units is not an issue (Enforcement Staff and Dorchester, Initial Brief at 206). It notes there is no evidence that any well or any lease utilized a refrigeration unit or counted liquids extracted by such unit in conjunction with the initial well classification test required by the Railroad Commission, and concludes that since the wells were classified as oil wells, there can be no issue involving the use of refrigeration units.

The Producer Group contends that Enforcement Staff and Dorchester have nowhere proven that gas must be "true casinghead gas" to receive NGPA Section 103 prices, nor have they shown anything to support this position in the legislative history of the NGPA or Commission rules and regulations. Finally, the Producer Group points out that the Commission has continued to approve Section 103 determinations after the date of its Show Cause Order in response to

applications where the applicant has identified up-hole brown dolomite perforations.

Respondent Lucky Bird Petroleum, Inc. (Luck Bird) filed a supplement to the initial brief of the Producer Group. Lucky Bird supports the Producer Group's position that the Commission has no jurisdiction to make findings of the allegations set forth in the Show Cause Order. Lucky Bird further argues that the dispute between Enforcement Staff and Dorchester and the Producer Group regarding the definition of casinghead gas does not affect Lucky Bird because the lease assignment it holds, which originally was given by Stanley Marsh of Hagy, Harrington and Marsh, states: "It is understood that casinghead gas produced from an oil-bearing strata shall be considered as oil." (Exhibits 392 and 393). Lucky Bird's evidence is that in three of its four wells named in this proceeding the drill samples from the depth at which it is producing gas also contained free oil (Tr. 2661-2662). Lucky Bird argues that this means that the gas it produces comes from an oil-bearing stratum.

Lucky Bird contends that its wells have no appreciable effect on Dorchester' Pickens well, located on the same section (640 acres) as the Lucky Bird-Thornburg lease, because the pressure versus cumulative production curve of the Dorchester well shows a straight line decline which is typical of the entire field after initial production decline has settled down. Lucky Bird concludes that the pressure in the Dorchester Pickens No. 1 well is affected only by production in that well, since its production increased substantially after it was fractured, which Lucky Bird claims led to the dramatic pressure drop. Lucky Bird alleges that its wells are in a geological trough, down structure from the Pickens No. 1 well (Tr. 2663-64). Lucky bird concludes that its gas production would not

otherwise be produced at all (Lucky Bird Brief at 6). Lucky Bird notes that it has made full disclosure of all of its perforations (Tr. 2655) and it contends that, based upon Enforcement Staff's own expert witness' testimony, pressure in the Dorchester Pickens well dropped less from 1981-1984 (when the Lucky Bird wells were completed) than for the 1966-1979 period (Exhibit 309); that Lucky Bird's wells make their gas-oil ratio unassisted by refrigeration units (Tr. 2701); that the Lucky Bird lease has historically had good oil production (Exhibit 390 at 25); and that a continuing increase in the Btu content of Lucky Bird's gas may only be explained by the gas being in contact with oil in the reservoir (Exhibit 390 at 20).

Respondent Meyer Farms, Inc. (Meyer Farms), owner of Coffee wells Numbers 1,2 and 3, maintains that its wells were completed and perforated solely in the granite wash (Exhibit 476). Meyer Farms' oil rights came from the original landowners, to whom the oil rights were reassigned by D.D. Harrington by an instrument dated July 30, 1938. Meyer Farms claims it has no connection with Panoma, and is not subject to any obligation of the Panoma-Northern contract (Meyer Farms Initial Brief at 2). Meyer Farms argues that the Commission cannot decide questions of dedication and abandonment because these issues require a determination as to whether the gas in question is casinghead gas, and, if so, who owns it under Texas law. It notes that Enforcement Staff and Dorchester did not do a phase equilibrium, test units wells, and their witness expressed an opinion on whether the gas produced from each study are, except for 15 (where the Meyer Farms wells are located), is casinghead gas (Exhibit 104 at 206). Meyer Farms points to numerous general statements in the record that it claims have no applicability to its wells and concludes that Enforcement Staff and Dorchester's position is directed to

wells completed and perforated in the brown dolomite, and the production of gas therefrom, as contrasted with its wells, which are perforated solely in the granite wash (Exhibit 476).

Meyer Farms notes that Enforcement Staff and Dorchester do not claim directly that its wells were perforated in the brown dolomite (Exhibit 104 at 233-241). It contends it has not violated Section 7(b) of the NGA for this reason, and because the casinghead gas it sells to Getty remains in interstate commerce after it is processed (through resale to Northern Natural) so that an abandonment application is not necessary.

On the dedication issue, Meyer Farms maintains its wells fall outside the scope of Enforcement Staff and Dorchester's presentation based on the admission by Northern's witness (Tr. 2585-2586):

> "Q. You could have, say, on Dorchester acreage, say, in study area No. 11 here, on Exhibit Number 34, you could have wells- - either Dorchester's wells or some other wells--drilled into the granite wash and/or below sea level, and Northern would not view those wells as dedicated to it under the 1952 contract?
>
> A. That's correct."

Finally, Meyer Farms argues that because its wells are completed and perforated only in the granite wash, Enforcement Staff and Dorchester's argument that respondents' wells with up-hole completions can qualify for Section 103 pricing only if each operator first obtains the requisite "effective and efficient drainage" finding under Commission Order No. 149, 18 CFR § 271.305, is inapplicable as to it.

Respondent J.B. Watkins (Watkins) argues that the determination of whether it is producing "dry gas" involves factual finding concerning the lithology underlying its wells, and its completion and production practices. It contends these matters are beyond the Commission's NGA jurisdiction and that the NGPA Section 503(c) gives the state agency having regulatory jurisdiction with respect to the production of natural gas the responsibility for making the factual findings regarding well category determinations. Watkins would have the Commission defer on these issues to the Texas regulatory agency and state courts. It maintains that state, not federal law, should determine the definition of casinghead gas and whether gas is being properly produced from a valid oil well. Watkins does not dispute that the Commission should determine whether particular casinghead gas is dedicated to interstate commerce or whether the price received for such gas exceeded the maximum lawful price, but it contends that in determining what constitutes casinghead gas the Commission must correctly identify and properly apply Texas law because failure to do so could be "outcome determinative" in view of the Watkins facts, and thus could constitute reversible error (Watkins Reply Brief at 3).

Watkins contends there is no evidence in any Railroad Commission order to support Enforcement Staff and Dorchester's regulatory expert's position that the West Panhandle gas field is that portion of the reservoir lying above the gas-oil contact, and the Panhandle (Gray County) and Panhandle (Carson County) oil fields are that portion of the reservoir lying below the gas-oil contact (Exhibits 589, 590, 592, 595, 597, 307 and 309). Watkins argues further that the order cited by the witness does not support his theory, and that the witness paraphrased the order he relied

on and did not submit the whole order into the record (Exhibits 583; Watkins Initial Brief at 49-50).

Watkins presented a reservoir engineer who testified that all the gas from the Watkins wells is casinghead gas since it was in association with oil in the reservoir and is being produced with that oil (Exhibit 510 at 33):

> In a formation such as the Brown Dolomite, there is vertical as well as horizontal communication between gas and oil. The area of vertical communication is known as the transitional zone....It is a customary, prudent production practice to perforate a wellbore to recover oil from the transitional as well as below the transitional zone. Production of free, associated natural gas necessarily accompanies the production of oil.

This expert defined casinghead gas as any gas or vapor indigenous to an oil stratum and produced from the stratum with oil, but he argued that in practical terms, a good definition is all hydrocarbon gas produced from any well classified by the Railroad Commission as an oil well (Exhibit 570 at 15).

Because Watkins wells are perforated only in the brown dolomite it contends the gas and oil produced from these wells comes from the same stratum. It relies on its expert's testimony that its oil and casinghead gas production comes from a "transition zone" where gas is mixed with and in contact with oil and which lies below the gas-oil contact (Exhibit 510; Watkins Reply Brief at 10), to explain Enforcement Staff and Dorchester's expert's tentative conclusion on the Watkins wells that "although it is possible that oil is being produced from

the brown dolomite formation, not all of the gas being produced is produced with that oil" based on the high gas-oil ratios and a phase envelope for the Watkins Bell A No. 1 well which has a somewhat different shape than a phase diagram for a well which has a somewhat different shape than a phase diagram for a well producing only casinghead gas (Exhibit 104 at 207). Watkins maintains that even if phase diagrams are valid to determine the phase of hydrocarbons in the reservoir, it is impossible to determine whether that gas was in equilibrium with oil in a reservoir based on a sample comprised of gas only (Reply Brief at 9).

Watkins does not claim the right to produce "dry gas," or gas that is not a necessary incident to the production of oil; but it does claim the right under Texas law and Railroad Commission regulations to produce oil and associated free gas from the transition zone, as Mr. Watkins identifies that zone relying on his experience in the field generally and specifically in "sitting" on the wells on adjoining acreage, his review and interpretation of gamma ray and neutron logs, and his observation of oil-stained drilling samples (Reply Brief at 12).

Watkins notes the phenomenon of coning: the creation of a mobile gas phase in the vicinity of a well bore caused by pressure reduction due to the withdrawal and production of hydrocarbons which can lead to associated free gas even in the portion of a reservoir that exhibits one hundred per cent permeability to the oil phase (Watkins Reply Brief at 11-12). It claims this phenomenon may account for the difference in gas-oil ratios on initial potential test ranging from 5,000 to 1 to 30,000 to 1, to a lease basis annual average of from 40,000 to 50,000 to 1 several years after production began (Watkins Initial Brief at 57; Tr. 3660-3662), and could also account for the

difference between the phase diagram from the Watkins Bell "A" No. 1 well and the phase diagram from the Phillips Thornburg No. 1 well as constructed by Enforcement Staff's witness (Exhibit 101; Watkins Reply Brief at 6-7).

Watkins contends that the evidence addressed in this proceeding did not produced a consistent opinion as to whether current gas-oil ratios or initial potential gas-oil ratios are appropriate for determining whether a well comports with the "excessive gas-oil ratio standard" as an Enforcement Staff witness characterized the Watkins wells, nor as to what production gas-oil ratios are high or too high. Watkins claims Enforcement Staff does not have the authority to second-guess the Railroad Commission and challenge as too high gas-oil ratios of 40,000 or 50,000 to 1 (Watkins Initial Brief at 58).

Watkins contends that there is no credible evidence that its oil wells are drawing gas from the area that would otherwise be produced by a Dorchester well. In support it cites: 1) the location of the Dorchester well in the northeast corner of Section 183 rather than in the center of the 640 acre section; 2) the location of the Watkins wells in a low area, down dip, or fault, at a subsea depth considerably lower than the depth of the Dorchester well open-hole completion; 3) the lower pressure in the reservoir; 4) the difference in Btu content between gas produced by the Dorchester well and the Watkins wells; 5) the difference in specific gravity of the gas; and 6) the uncontroverted testimony by the Watkins witness that the cumulative casinghead gas production from all the Watkins wells does not equal the acre-feet of associated gas that originally underlay even one of the drilling units assigned to a Watkins oil well (Watkins Initial Brief at 58-63; Exhibit 510 at 28).

Watkins argues that the record does not contain sufficient evidence that it has committed the violations alleged. It notes the conclusions of the expert sponsored by Enforcement Staff and Dorchester were "difficult" and "tentative" (Exhibit 264 at 26, Exhibit 104 at 207), and Watkins notes that that the regulatory expert found a hypothetical oil operator similar to Watkins in compliance with all Railroad Commission rules (Watkins Initial Brief at 63-67). Particularly noteworthy to Watkins wells was casinghead gas and that he would not need a recombination analysis to tell him so (Watkins Reply Brief at 29; Tr. 3662-63), a position Watkins claims undermines another expert who had tentatively concluded that one or more of the Watkins wells maybe producing gas from above a gas-oil contact point (Watkins Initial Brief at 43-55; Watkins Reply Brief at 28-30).

Watkins claims it is patently unfair to hold it liable for overcharges under the NGPA when it has complied with the requirements of both the Railroad Commission and this Commission. Watkins prays for costs, plus attorney's fees under Commission Rule 604 because of Enforcement Staff's unreasonable refusal to admit until it filed its Initial Brief that Watkins produces crude oil from the brown dolomite.

Cabot's expert in Texas oil and gas law testified that casinghead gas is gas produced with oil from an oil well and that casinghead gas was not dedicated to the interstate market under the 1952 contract because the contract provided that the seller shall not be obligated to drill more than one well for the production of gas on 640 acres (Exhibit 466 at 14). Because 640 acres is the general spacing for a gas well in the West Panhandle Field, the expert concludes that the parties contemplated the sale of gas from gas wells, and not from oil wells (*id.* at 20).

Cabot, while fully supporting the Producer Group, stresses three Arguments:

(1) Casinghead gas is not dedicated to interstate commerce, thus there is not now, and never was, a need to obtain abandonment under Section 7(b) of the NGA; and

(2) Any gas from a well classified by the Railroad Commission as an oil well is casinghead gas, and any challenge either to the classification of the well or the character of the gas must be pursued in a state forum; and

(3) Enforcement Staff presented in its rebuttal case a new theory that any well producing above a gas-oil ratio of 2000 to 1, would indicate perforations in the free gas zone above the gas-oil contact in violation of Railroad Commission rules (Enforcement Staff and Dorchester Brief 189-211; Tr. 1119-22; 1156-57).

Cabot's third argument rests on its position that there was a violation of due process since Enforcement Staff and Dorchester did not put forward their theory until the filing of rebuttal testimony and there was nothing in the Show Cause Order which could have alerted Cabot to this theory; thus Cabot did not have notice and could not defend against the rebuttal case (Cabot Reply Brief at 29-31). Cabot also contends that the Presiding Judge's refusal to allow the Producer Group and Cabot to submit affirmative evidence opposing this rebuttal case, in the form of Railroad Commission employee depositions and additional witnesses on well classification procedures, was a denial of procedural due process. Finally Cabot believes that the gas-oil contact theory is a matter of state law, and one where the Commission should defer to the expertise of the state courts and regulatory agencies.

The Consolidated Royalty Owners (CRO) supports the Producer Group. CRO also argues that the NGPA, its legislative history, and the cases interpreting and applying the NGPA leave no doubt that:

1. All natural gas produced from wells qualifying under Section lO3(c) is eligible to be sold at the NGPA Section 103 ceiling price, whether or not some of the gas also falls within NGPA Section 104: and

2. The Commission's NGA Section l(b) jurisdiction terminated on December 1, 1978, as to first sales of all natural gas produced from wells qualifying under NGPA section lO3(c) (CRO) Initial Brief at 6).

Since NGPA Section 103(c) defines a new, onshore production well and makes no distinction between gas produced from different completion locations, wells determined by the Railroad Commission to have qualified as new onshore production *ipso facto* qualify to charge Section 103 prices for all gas produced by them even if that gas, or some of it, could also quality for Section 104 pricing (see NGPA Section 101(b)(5) which provides that if gas qualifies under more than one provision of the statute, the provision resulting in the highest price is applicable). Thus, even if certain of the gas produced from a new onshore production well is gas that qualifies under NGPA Section 104, that gas is eligible to receive the NGPA Section 103 ceiling price because all natural gas produced from a new onshore production well qualifies for the NGPA Section 103 ceiling price. CRO's basic position is that once well determinations are final and binding, the legal status of the NGPA Section 103(c) wells cannot be questioned (CRO Initial Brief at 11).

Relying in part on the Commission's Notice of Proposed Rulemaking, "Deregulation and Other Pricing Changes on January 1, 1985, Under the Natural Gas Policy Act", Docket No. RM84-14-000 (September 13, 1984), and also no the legislative history of the NGPA, CRO contends that Section 601(a)(1)(B) of the NGPA has removed natural gas that is produced from wells qualifying for NGPA Section 103(c) from the Commission's NGA abandonment jurisdiction (*Pennzoil Co. v. FERC*, 645 F.2d 360 (5th Cir. 1981) *cert. denied*, 454 U.S. 1142 (1982).

Getty contends the Commission lacks jurisdiction and competence to make the findings required, citing Section 1(b) of the NGA and *Burford v. Sun Oil Co.*, 319 U.S. 315, *reh. denied*, 320 U.S. 214 (1943) and later cases. According to Getty the Commission's Show Cause Order has had the effect of reopening respondent's Section 103 well determinations in violation of Section 503 of the NGPA. Getty contends that until the Commission reopens and vacates respondents' final Section 103 determinations in accordance with the statutory standard and applicable regulations, these determinations are binding, and the Commission is without jurisdiction to investigate or remedy alleged violations of the NGA, or to question Section 103 pricing, with respect to gas covered by such final determinations. See NGPA§§103 and 601(a)(1)(B), 15 U.S.C. § 3431(a)(1)(B) (1982) (Getty Initial Brief at 35).

VI. FINDINGS

To determine whether respondents are violating Section 7(b) of the NGA and/or Section 504(a)(1) of the NGPA as alleged in the Show Cause Order it is necessary to decide (1) whether certain respondents are

correct that the Commission does not have jurisdiction in these matters; (2) if the Commission has jurisdiction should it defer to state tribunals, should it initiate a joint board composed of state representatives pursuant to Section 17 of the NGA or should it here decide the central issue which is whether gas that was dedicated to interstate commerce is being unlawfully diverted or illegally priced, and (3) if all gas except casinghead was dedicated to interstate commerce what is the definition of casinghead gas, and are respondents producing and selling gas other than casinghead gas. No one has sought to remove from interstate dedication the gas from the land in question via an application pursuant to Section 7(h) of the NGA.

I deny the Producer Group's renewed motion for summary disposition (Producer Group's Initial Brief at 18) and I reject respondents' arguments that the Commission lacks jurisdiction because of Section 1(b) of the NGA ("The provisions of this Act shall apply...to the sale in interstate commerce of natural gas for resale...but shall not apply...to the production or gathering of natural gas." and/or Section 601(a)(l)(B) of the NGPA ("Committed or dedicated natural gas.--...for purposes of section 1(b) of the Natural Gas Act, the provisions of such act and the jurisdiction of the Commission under such act shall not apply solely by reason of any first sale of natural gas which is committed or dedicated to interstate commerce as of the day before the date of the enactment of this Act and which is...(iii) natural gas produced from any new, onshore production well (as defined in section lO3(c) of this Act)").

Respondents' emphasis on the above quoted exemptions obscures the fact that in this proceeding the Commission is not attempting to regulate respondent's production activities but is investigating

whether respondents violated and are violating federal statutes. Sections 14, 16 and 20 of the NGA and Sections 501 and 504 of the NGPA authorize Commission action to end violations of the respective statutes. I reject respondents' position because it would lead to the absurd result that the Commission is powerless to determine whether producers are violating Federal law that Congress determined the Commission alone should enforce.

The case law on the question of jurisdiction has established the principle that the NGA Section 1(b) exemptions are to be strictly construed (*Shell Oil Co. v. FERC*, 566 F.2d 536 at 539 (5th Cir. 1978); *Public Service Commission of Kentucky v. FERC*, 610 F.2d 439 (6th Cir. 1979); and *Interstate Natural Gas Co. v. Federal Power Commission*, 331 U.S. 682 (1947)) and has made the common sense distinction between direct efforts by the Commission to regulate production, on the one hand (*Shell Oil Co. v. FERC, supra*), and on the other, the Commission's consideration of production and other non-jurisdictional activities in the course of its regulatory activities within its jurisdiction (*Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581 (1945); *Public Service Commission of the State of New York v. FPC*, 287 F.2d 143 at 146 (D.C. Cir. 1961), and *Henry v. FPC*, 513 F.2d 395 (D.C. Cir. 1975)). No one here can reasonably dispute this Commission's exclusive jurisdiction to determine whether gas which had been dedicated to interstate commerce is being unlawfully diverted or priced illegally (*Mitchell Energy Corp. v. FERC*, 533 F.2.d 258 (5th Cir. 1976); *Panhandle Eastern Pipe Line Co. v. Michigan Consolidated Gas Co.*, 177 F.2d 942 (6th Cir. 1949)). I find that the Commission has such jurisdiction.

It is necessary to consider next whether the Commission should defer to the Texas state courts and

the Railroad Commission in deciding certain material questions or, alternatively, to refer them to a joint board under Section 17 of the NGA. I reject both of these proposals because the issues involve the interpretation and application of federal statutes; and the alleged violations are ongoing, so that despite the number of participants, the complicated factual situations and extensive legal argument, the Commission's mandate is clear that a decision should be issued at the earliest possible date.

The question of what gas from the land covered by the Show Cause Order was dedicated to interstate commerce requires an interpretation of the 1952 gas sales contract between Panoma and Northern Natural because on June7, 1954, the date the Commission began regulating producer gas sales in interstate commerce, gas from this acreage was being delivered to Northern Natural under the terms of that contract. Enforcement Staff and Dorchester's summary is accurate (Enforcement Staff and Dorchester Initial Brief at 96):

"The commencement of deliveries of natural gas in interstate commerce is the act which, standing along, dedicates natural gas from those properties and makes that natural gas subject to the Commission's authority." *Mountain Fuel Supply Co. and Wexpro Co.*, 24 FERC ¶ 61,120 at 61,293, *rehearing denied*, 24 FERC ¶ 61,321 (1983); *see also J.M. Huber Corp. v. FPC*, 236 F.2d 550, 556-668 (3rd Cir. 1956), *cert. denied*, 352 U.S. 971 (1957); *Tenneco Exploration, Ltd. v. FERC*, 649 F.2d 376, 379-380 (5th Cir. 1981).

Dedication, coextensive with the obligation to continue service, attaches not to an individual sale or producer, but to the gas itself. *El Paso Natural Gas Co.*, 54 FPC 145, 149 (Opinion No. 737, 1975); *108/Hunt v.*

FPC, 306 F.2d 334, 342 (5th Cir., 1962), *reversed on other grounds*, 376 U.S. 515 (1964). *109/*

108/ Opinion No. 737 was eventually affirmed by the Supreme Court in *Southland*. The subsequent history of Opinion No. 737 is as follows: *rehearing denied*, 54 FPC 917 (Opinion No. 737-A, 1975) *modified* 54 FPC 2821 (Opinion No. 737-B, 1975), *reversed, Southland Royalty Co. v. FPC*, 543 F.2d 1134 (5th Cir. 1976), *reversed, California v. Southland Royalty Co.*, 436 U.S. 519 (1978).

109/ The court in *Hunt* stated: "Like the ancient covenant running with the land, the duty to continue to deliver and sell flows with the gas from the moment of the first delivery down to the exhaustion of the reserve, or until the Commission, on appropriate terms, permits cessation of service under 7(b), 15 U.S.C.A. 717f(b)."

Based on the undisputed facts, i.e. that on June 7, 1954, Panoma was delivering to Northern Natural, an interstate pipeline company, gas from 93 of the wells which now belong to Dorchester, that thirty-five of these wells are on the land which is the subject of this proceeding (Exhibit 4 at 10), that the 1952 contract described the gas to be delivered and purchased as "all of the natural gas produced from the wells now drilled and hereafter to be drilled" on the subject acreage (Exhibit 7, Article I) contained no express restrictions on the type of gas to be sold, and only reserved to the seller the right to natural gasoline and other liquefiable hydrocarbons, it would seem at first blush, that Enforcement Staff and Dorchester are correct that the contract means that the parties intended "all...gas" to mean all gas including casinghead gas. However, where the contract contains arguably ambiguous language, the courts have long recognized that it is proper to use as aids for interpretating the intent of the

parties various features of the whole contract, circumstantial evidence, and the technical meanings accorded the terms and phrases used. *United States v. ITT Continental Baking Co.*, 420 U.S. 223 at 238 (1974); *Sam Rayburn Dam Electric Cooperative v. FPC*, 515 F.2d 998 at 1003 (D.C. Cir. 1975); *Energy Oils, Inc. v. Montana Power Co.*, 626 F.2d 731 (1980); *Moore v. Tristar Oil and Gas Corp.*, 528 F.Supp. 296 at 308 (1981). As noted in a well known treatise on contracts, no word or phase has one true and unalterable meaning (*Corbin on Contracts*, One Volume Ed., Chap. 24, Sec. 535, p. 495-497 (1952)):

Sometimes it is said that "the courts will not disregard the plain language of a contract or interpolate something not contained in it"; also "the courts will not write contracts for the parties to them nor construe them other than in accordance with the plain and literal meaning of the language used." It is true that when a judge reads the words of a contract he may jump to the instant and confident opinion that they have but one reasonable meaning and that he knows what it is. A greater familiarity with dictionaries and the usages of words, a better understanding of the uncertainties of language, and a comparative study of more cases in the field of interpretation, will make one beware of holding such an opinion so recklessly arrived at. (Footnotes omitted.)

Corbin continues (*ibid.* Sec. 536, p. 499-500):

In view of all this, it can hardly be insisted on too often or too vigorously that language at its best is always a defective and uncertain instrument, that words do not define themselves, that terms and sentences in a contract, a deed, or a will do not apply themselves to external objects and performances, that the meaning of such terms and sentences consists of

the ideas that they induce in the mind of some individual person who uses or hears or reads them, and that seldom in a litigated case do the words of a contract convey one identical meaning to the two contracting parties or to third persons. Therefore, *it is invariably necessary*, before a court can give any meaning to the words of a contract and can select one meaning rather than other possible ones as the basis for the determination of rights and other legal effects, *that extrinsic evidence shall be heard* to make the court aware of the "surrounding circumstances," including the persons, objects, and events to which the words can be applied and which caused the words to be used. (Emphasis added and footnote omitted.)

I find relevant in ascertaining what the parties to this contract meant and how it should be interpreted, the following extrinsic evidence:

1. Contract to the typical situation (1 Williams and Meyers, *Oil and Gas Law*, § 291.7 at 292-292.1 (1983)), it was and is common in the West Panhandle Field to divide the ownership of oil rights and gas rights (Exhibit 402 at 12-13, *passim*).

2. Northern Natural, one of the parties to the 1952 contract, claims it did not thereby receive the rights to casinghead gas because the contract when read as a whole refers only to gas rights and does not mention oil rights. Northern Natural emphasizes that the contract dedicated gas rights in gas lands and leases and placed on the seller the obligation to drill wells on 640-acre spacing. (Initial Brief at 41-44, Reply Brief at 5-6). Northern Natural acted on its belief by entering into contracts to purchase casinghead gas produced from the acreage covered by the 1952 contract before this litigation began (Exhibits 372-378, 402 at 18).

3. Lawrence Hagy stated that he did not intend to assign his oil rights to Panoma, and Panoma's President, Donald Harrington, acknowledged on October 10, 1949, that Lawrence Hagy was beneficial owner of a one-third interest in the oil and oil rights under the subject acreage (Exhibit 407 and Tr. 2747-2749). Evidence of Mr. Harrington's action in 1953 and Mr. Hagy's actions since 1949 are consistent with Mr. Hagy's present understanding.

4. Casinghead gas did not move from the subject acre into the interstate market on or prior to June 7, 1954, and Northern Natural has never bought casinghead gas from Dorchester from this acreage (Tr. 2590).

5. Dorchester and Enforcement Staff's claim here that casinghead gas from the subject acreage is dedicated to interstate commerce and covered by the 1952 contract is inconsistent with Dorchester and Northern Natural's prior actions, Dorchester abandoned its Bobbit No. 1 well, located on acreage subject to the 1952 contract, in 1970 when the well's relative oil and gas production changed and it was reclassified as an oil well. The 1970 lease by Dorchester to the oil well operator acknowledges Dorchester's ownership of the gas leasehold estate. It notes the lessee's desire to use the existing casing to produce oil and casinghead gas, and grants Dorchester an undivided one-half of all casinghead gas produced for consideration for the use of the casing Dorchester had installed on the well (Exhibit 29). In 1970 Dorchester did not attempt to exercise ownership of casinghead gas from this well (Exhibits 29 and 31), and did not file an abandonment application with the Commission (Tr. 347). Northern Natural, consistent with its position that casinghead gas was not dedicated to interstate commerce, removed

its equipment from the Bobbit No. 1 well when it was reclassified as an oil well (Tr. 2469).

Based on the evidence detailed above, I find that the 1952 gas purchase contract under which deliveries took place and commitments existed on June 7, 1954 and which was the basis for the Commission's later grant of a certificate of public convenience and necessity did not include casinghead gas so that casinghead gas from the subject acreage was not, and is not, by virtue of the 1952 contract dedicated to interstate commerce.

The next question is what is meant by "casinghead gas." The term is not defined in the two federal statutes at issue--the NGA and the NGPA, but it is defined by the State of Texas. I find casinghead gas to be any gas and/or vapor indigenous to an oil stratum and produced from the stratum with oil. I reach this conclusion for several reasons. First, it is the definition the State of Texas has formally adopted and used for nearly fifty Years. (Tex. Nat. Res. Code Ann. § 86.002(10) (Vernon 1978); Title 16, Texas Administrative Code, Section 3.69 Definitions, Railroad Commission Rule 051.02.02.079; Act of May 1, 1935, ch. 120, 1935 Tex. Gen Laws, amending Art. 6008 of the Revised Civil Statutes of Texas of 1925. *See* Cheek, *Legal History of Conservation of Oil and Gas* 280 (1938)). Second, this definition is supported by persuasive expert scientific and engineering testimony (Exhibit 104, *passim*; Exhibit 264 at 44; and Tr. 891, 1025). Third, this finding is in keeping with the language in *FPC v. Panhandle Eastern Pipe Line Co.*, 337 U.S. 498 at 513 (1949), that state and federal regulation should produce harmonious regulation.

> The Natural Gas Act was designed to supplement state power and to produce a

> harmonious and comprehensive regulation of the industry. Neither state nor federal regulatory body was to encroach upon the jurisdiction of the other. Congress enacted this Act after full consideration of the problems of production and distribution. It considered the state interests as well as national interests. (Footnote omitted.)

This is not to say that the Commission, as matter of law, would be bound to apply a state definition if such definition was unreasonable on its face; or if its adoption would necessarily frustrate implementation of the purpose of the federal statutes, *see, e.g., United Gas Improvement Co. v. Continental Oil Co.*, 381 U.S. 393, 400 (1965) (the purposes of the Natural Gas Act would be frustrated if regulation thereunder were made to depend upon technical title concepts of local law). Finally, the definition advocated by respondent's "any gas produced from an oil well" places the emphasis on the well type rather than what the well produces, and would lead to the absurd conclusion that regardless of how the well got to be categorized as an oil well the gas it produced would automatically be casinghead gas without regard to what scientific tests showed it to be, and without regard to the State's own statutory and regulatory definition of casinghead gas.

Once gas is dedicated to instate commerce it remains dedicated until the Commission finds under the NGA the dedication is no longer necessary in the public interest (*Amoco Production Co.*, 23 FERC ¶ 61,211 at 61,429-61, 430 (1983); *Argo Oil Corp.*, 15 FPC 601, 622 (1955); *J.M. Huber*, 14 FPC 340, 341-342, 348-350 (1955), *aff'd J.M. Huber Corp. V. FPC*, *supra*; *Dixie Pipe Line Co.*, 14 FPC 106, 111-115 (1955)), or unless it falls within the scope of Section 601 of the NGPA,

Respondents contend that even if gas was once dedicated, the Commission's jurisdiction ended pursuant to Section 601 of the NGPA when they received their final Section 103 well determinations. Determinations that a particular well or gas is eligible for incentive pricing under Section 102, 103, 107 or 108 of the NGPA are final and binding once they are no longer subject to Commission or judicial review unless based on an untrue or omitted statement of material fact (*Ecee, Inc. v. FERC*, 645 F.2d 339 at 345 (5th Cir. 1981)).

For the following reasons I reject respondents' argument that NGPA Section 601 removes the gas in question from the Commission's jurisdiction. The evidence is persuasive that many respondents received Section 103 determinations based on submissions showing no perforations in the brown dolomite and then they subsequently made such perforations and did not inform the Railroad Commission even though Railroad Commission regulations require the submission of amended W-2 forms in such a situation (Exhibit 306). Since Railroad Commission regulations prohibit perforations by oil wells above the gas-oil contact this information would seem to merit the designation omission of a material fact as that term is used in NGPA Section 503(d)(l). However, the logic of this reasoning is countered by the fact that the Railroad Commission has granted and this Commission has left undisturbed some 55 Section 103 determinations to respondents where the applications showed perforations in the brown dolomite (Exhibit 331). This suggests that perforation in the brown dolomite is not necessarily inconsistent with an oil well classification, depending on the location of the gas-oil contact. For purposes of this proceeding, I accept the fact that respondents have final Section 103 well determinations but I find these determinations cover

only casinghead gas,i.e., gas indigenous to an oil stratum and produced from that stratum with oil. This finding is required by the logic and language of the NGPA and the integrity of the regulatory scheme. Section 103 states:

> SEC. 103. CEILING PRICE FOR NEW, ONSHORE PRODUCTION WELLS. (a) APPLICATION--in the case of natural gas determined in accordance with section 503 to be produced from any new, onshore production well, the maximum lawful price computed under subsection (b) shall apply to any first sale of such natural gas delivered during any month.
>
> * * *
>
> (c) DEFINITION OF NEW, ONSHORE PRODUCTION WELL.--For purposes of this section, the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)--
>
> (1) the surface drilling of which began on or after February 19, 1977;
> (2) which satisfies applicable Federal or State well-spacing requirements, if any; and
> (3) which is not within a proration unit--
>
> (A) which was not in existence at the time the surface drilling of such well began;
> (B) which was applicable to the reservoir from which such natural gas is produced: and

(C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

Section 2 (8) states: PRORATION UNIT.--The terms "proration unit" means--

(A) any portion of a reservoir; as designated by the State or Federal agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well;

Section 2 (6) states: RESERVOIR.--The term "reservoir" means any producible natural accumulation of natural gas, crude oil, or both, confined--

(A) by impermeable rock or water barriers and characterized by a single natural pressure system; or
(B) by lithologic or structural barriers which prevent pressure communication.

I interpret this language to mean that the NGPA Section 103(c) definition of "new, onshore production well" does not apply to respondents' wells to the extent they are within an existing Dorchester proration unit which is applicable to the reservoir from which respondents' wells would produce gas. The evidence shows that most respondents' wells are producing gas which Dorchester would otherwise produce from its existing proration units and the Railroad Commission

has made no finding that respondents' wells are necessary to effectively and efficiently drain that portion of the reservoir from which Dorchester's wells are producing gas. According to the NGPA Section 103(c), these respondents are therefore not entitled to a Section 103 well category determination for gas from the Dorchester proration units. Consistent with this holding is the reasonable assumption that the Railroad Commission's grant of Section 103 status was in keeping with the Texas statutory definition of casinghead gas so that respondent oil well operators' Section 103 determinations cover only gas from below the gas-oil contact, i.e. gas indigenous to an oil stratum and produced from the stratum with oil. This rationale may also explain why neither the Railroad Commission nor this Commission has acted to reopen respondent's Section 103 determinations.

The result reached here comports with the purpose and preserves the integrity of both the NGA and NGPA. The argument urged by respondent's would, to the contrary, lead to the unwarranted conclusion that, with the NGPA, Congress intended that gas already dedicated to interstate markets under the NGA could, without Commission authorization, denied to those markets which rely on that gas and instead sold elsewhere at incentive prices if produced from new wells for which, as to that gas, there was no economic justification. I find it unreasonable to assume that Congress intended incentive prices to apply to gas which would be produced from existing wells and for which the new wells were not necessary.

The final question is whether, based on the conclusions reached above, respondents have been and are continuing to violate federal law by unlawfully diverting dedicated gas to intrastate markets or are selling gas at prices higher than those allowed.

For the reasons stated below I find all respondent oil well operators named in the Show Cause Order, except Meyer Farms, Komanche Oil & Gas, Stowers Oil & Gas, and J.B. Watkins, to be selling in intrastate commerce gas which is dedicated to interstate commerce in violation of Section 7(b) of the NGA and at prices which violate Section 504 of the NGPA.

Since the Railroad Commission has established a division of the reservoir so that the Panhandle West Gas Field is that portion of the reservoir lying above the gas-oil contact, it follows that Dorchester's proration unit is that portion of the reservoir above the gas-oil contact which lies beneath each 640-acre unit assigned to a Dorchester well. Perforations in the brown dolomite by themselves are not conclusive evidence that respondents are producing and selling gas which was dedicated to interstate commerce by the 1952 contract and for which a just and reasonable rate was in existence on the day before the NGPA was enacted. What is determinative is whether or not respondents' gas production comes from above the gas-oil contact because this would mean that such production was not casinghead gas but was gas dedicated to interstate commerce and if produced from within a Dorchester proration unit was gas limited to Section 104 pricing. The location of the gas-oil contact is determined in each individual well bore and may vary from one well to another. Several respondents testified they did not know or bother to ascertain where the gas-oil contact was in their particular wells (Exhibits 582 at 2-3, Tr. 1634, 2887). Enforcement Staff and Dorchester located it directly in only one instance (Exhibit 74) but attempted to locate it for all respondents' wells indirectly by the secondary evidence set forth in their case-in-chief.

The basis of my findings is the totally persuasive evidentiary presentation of the expert witnesses sponsored by Enforcement Staff and Dorchester. This overwhelmingly convincing presentation is detailed in Appendix C and in the Argument. Except as to respondents Meyer Farms and J.B.Watkins, I accept these experts' conclusions set out in this appendix and in the Argument section of this Decision. These conclusions, based on accepted scientific principles of geology, chemistry, and reservoir engineering, leave no doubt that most of the gas produced by most of the respondents is not casinghead gas because it is not gas indigenous to an oil stratum and produced from that stratum with oil, and that most of the respondents are producing gas which would otherwise be produced by Dorchester. I reject respondents' position that the brown dolomite formation as encountered by all respondents' wells in the area covered by the Show Cause Order produces crude oil such as would justify a finding that their gas production from the brown dolomite was indigenous to an oil stratum. Respondents try to explain away the implications of the evidence but they do not deny as facts the very high gas-oil ratios from most of their wells which occurred after the wells were completed initially and when they were perforated up-hole in the brown dolomite, the precipitous drop in the pressure versus cumulative production curve of most of the 35 Dorchester wells which occurred at about the same time period, the results of the equilibrium tests and the geologist's description of the brown dolomite in each study area. The attacks on the results of the ASTM 86 distillation tests, the various hydrocarbon analyses including the recombination analyses and the phase diagrams were unsuccessful in demonstrating that the sponsoring witness did not know what he was doing, did not conduct the test properly or that the test did not produce a valid scientific result (Tr. 715-1468).

Even if true in every instance, the personal recollections and experiences testified to by respondents and witnesses for them do not refute the validity of the expert views of witnesses for Enforcement Staff and Dorchester. This is because it is obvious from the record that it is not usual, for example, to find shows of oil in cores and various kinds of rock samples but these isolated bits of visual evidence are unreliable indicators of whether crude oil will be produced at all, or in any meaningful quantities (Exhibit 73 at 17-18; Tr. 563-568).

I reject Producer Group's "vaporized oil" argument that all wells, including Dorchester's, perforated in the brown dolomite are producing gas which is associated in the stratum with crude oil and thus is casinghead gas. Even if it is true that some of the brown dolomite gas production may derive from the vaporization of crude oil as reservoir pressure declines, such gas is not crude oil under any reasonable and practical understanding of that term nor does it come within the definition of casinghead gas that I have adopted in this proceeding. Producer Group's argument, if accepted, would lead to the self-contradictory conclusion that Dorchester's wells which produce no crude oil are nonetheless producing casinghead gas.

I do not find that Meyer Farms has committed the violations alleged. Even under the substantial evidence standard (NGA Section 19(b); NGPA Section 506(a)(4)), the fact of high gas-oil ratios by itself is not persuasive that this respondent's gas production was not casinghead gas. No phase equilibrium studies are in evidence for these wells. I note that the Meyer Farms testimony that its three wells are completed only in the granite wash went into the record without any cross-examination (Exhibits 476-489; Tr. 3054).

Also Enforcement Staff and Dorchester's third expert claimed the lease's gas production volumes were quite substantial "beginning in 1981" (Exhibit 104 at 238), yet the evidence shows they were considerably higher in 1970 through 1976, years that predate the NGPA (Exhibit 242). The expert sponsored by Enforcement Staff and Dorchester admitted that the results of the pressure versus cumulative production curve for the Dorchester well was inconclusive that Meyer Farms' Coffee lease was draining the Dorchester well, and this was the only study area where he did not come to a definitive conclusion that the respondent's gas production was or was not casinghead gas. Taken all together, I find the evidence of the lease's atypical gas-oil rations insufficient to support the alleged violations, and I recommend that the Commission undertake to get additional information to determine whether this respondent has committed the violations alleged in the Show Cause Order.

I find that Lucky Bird Petroleum and those respondents shown on Appendix C to Producer Group's Initial Brief and those named in Exhibit 599 have committed the alleged violations notwithstanding that these respondents derive their title to oil and casinghead gas outside the chain of title that went from Hagy, Harrington and March to Panoma. The essential fact, which no one has refuted successfully, is that the gas rights in all this acreage are dedicated to interstate commerce; and this dedication includes all gas except casinghead gas as previously defined.

As to the three respondents who are selling gas in interstate commerce, I find based on the expert testimony summarized in Appendix C that Komanche Oil & Gas and Stowers Oil & Gas have violated NGPA Section 504 by selling gas dedicated to interstate commerce at prices higher than what the NGPA allows.

I find that the evidence is not persuasive that J.B. Watkins has committed similar violations of the NGPA (Exhibits 104 at 207, 264 at 26; Tr. 3662-63). The evidence shows J.B. Watkins to be the only respondent whose wells produce crude oil and gas from the brown dolomite. Contrary to the assertion by the third expert sponsored by Enforcement Staff and Dorchester (Exhibit 264 at 27), which was repeated in some briefs, there was no admission by the Watkins witness that Watkins perforated above the gas-oil contact. Unlike the other respondents, except Meyer Farms, Enforcement Staff and Dorchester's third expert qualified his conclusion as to J.B. Watkins. It is not sufficient in my judgement to find a respondent guilty of these serious violations based only on high gas-oil ratios and a "somewhat different" phase diagram. I do not find persuasive the conclusion made "tentatively" by an expert that something is "quite possible" when the same expert has been decisive in his opinions on the same subject as to other respondents. Here again I recommend that the Commission undertake to get additional information to determine whether this respondent has committed the alleged violations.

Because of the impact various factors had on the ultimate outcome of this proceeding, I find Enforcement Staff's refusal to enter a stipulation with J.B. Watkins that its crude oil production came only from the brown dolomite not be within that type of refusal covered by 18 CFR § 385,604. In addition such a stipulation would have been of no substantial importance since the critical distinction is the location of the gas-oil perforation in the brown dolomite. Therefore, I deny Watkins request for recovery of costs under Rule 604.

Finally, as requested by the parties, pages 129 through 132 of transcript Volume 26 from Texas

Railroad Commission Oil and Gas Division Docket No. 10-77, 314 is received in evidence as Exhibit 618, and the Judgement and Ordering Vacating Judgment in *Dorchester Gas Producing Company v. The Harlow Corporation, et al.*, Case No. 84-505910, 99th District Court, Lubbock County, Texas, are received in evidence as Exhibits 619 and 620, respectively.

VII. REMEDY RECOMMENDED

I recommend that the Commission order respondents, except Meyer Farms and J. B. Watkins, to cease immediately the violations of the federal statutes detailed in the preceding section of this decision, gather additional information as to these two respondents, and issue an order setting forth a procedural schedule for phase two of this proceeding promptly after the Commission's decision becomes administratively final.

/S/
Brenda P. Murray
Administrative Law Judge

APPENDIX A
LIST OF RESPONDENTS AND WELLS
STOWERS OIL & GAS COMPANY, ET AL.

Respondent	Well Name
1. Tony D. Richardson and J.C. Albin, d/b/a A & R OPERATING CO.	Sheridan #1 Sheridan #2
2. James R. Allen and John L. Womack, d/b/a ALMAC OIL COMPANY	Big Bull #1 Big Bull #2 Bucket Shop #1 Bucket Shop #2
3. ASPEN PETROLEUM, INC.	Harris #1 Harris #2 Harris #5 Harris #6 Fields #3 Fields #4 Fields #7 Fields #8 Warnick #1 Warnick #2 Warnick #3 Warnick #4 Bell #1 Bell #3 Sheridan #2 Sheridan #4 Sheridan #7 Sheridan #8 Jones #3 Jones #4 Jones #5 Jones #6 Chadwick #1 Chadwick #7

	Chadwick #8 Chadwick #9
4. BINK, INC.	Ann #1 Ann #2
5. Don Boddy and Shirley Boddy, d/b/a CADDO PRODUCTION	Faith #1A
6. CAPROCK ENGINEERS, INC.	Zack #1 Zack #2
7. DAHALO LEASE CORPORATION	Vanderburg #1 Vanderburg #2 Vanderburg A #1
8. ENERGY-AGRI PRODUCTS, INC.	Money #1 Money #2 Peeler II #1 Peeler #2 Peeler #3 Peeler #4 Henry #1 Henry #2 Henry #3 Henry #4
9. David Nall, d/b/a EZEKIEL ENERGY	Justin #1-2 Kelly #1-1
10. THE HARLOW CORPORATION	Beavers #1 Beavers #2 Beavers #3 Beavers #4
11. Judy Cook, Vernon Cook, and Jimmie	Bell #2 Boddy #1

Allen, d/b/a	Boddy #2
JUDY OIL COMPANY	Lloyd #2
	Lloyd #3
	Bell #3
12. KAARI OIL COMPANY, INC.	Haiduk "A" #1[7]
	Haiduk "B" #1[8]
	Columbia #1-3
	Columbia #2-4
	Haiduk "C" #1-13
	Haiduk "C" #2-14
	Haiduk "C" #2-18
	Haiduk "D" #4-22
	Future #3
	Future #4
	Future #1-5
	Future #2-6
	Future "B" 1-15
	Future "B" 2-16
	Randall #1
	Randall #2
13. KIM PETROLEUM CO., INC.	Dennis #1
	Dennis #2
	Dennis #4
14. Tonya Starbuck, V.T. Stowers,	Cobb #1
and K.A. Roberts, d/b/a	Cobb #2
KOMANCHE OIL & GAS	Cobb #3
	Cobb #4
	Cobb #5
15. LEAR OIL & GAS, INC.	Sandra #1
16. LUCKY BIRD PETROLEUM INC.	Thornburg #3
	Thornburg #4
	Thornburg #5
	Thornburg #6

17. MAGNET OIL, INC.	Dania #3
18. MEYER FARMS INC.	Coffee #1 Coffee #2 Coffee #3
19. DENNIS MILLS ENTERPRISES, INC.	Heidi #3 Heidi #4
20. Warren Chisum, d/b/a OMEGA ENERGY	Ginn #1 Ginn #2 Ginn #3
21. PANHANDLE ENERGY CORP.	Alley #1 Alley #2 Wade "L" #1
22. PANSTAR OIL & GAS, INC.	Hildreth #1 Hildreth #2
23. W. L. Bruce and James R. Allen, d/b/a PRAIRIE OIL COMPANY	Alley #2 Koell #1 Koell #2 Steel #1 Steel #2
24. RAVEN ENERGY, INC.	Jeanne #1 Jeanne #2 Snapp #1 Snapp #4 Martha #1 [10] Martha #2 [11]
25. SECURITY PETROLEUM DRILLING, INC.	Sheridan #2 Sheridan #4 Evans #1 Evans #4

	Evans #6 Evans #7 Evans #8
26. Sharon Caldwell Ward, d/b/a SHARON LEASE OIL CO.	Sharon #1 Sharon #2 Sharon #3 Sharon #4
27. L.R. Spradling and V.T. Stowers, d/b/a STOWERS OIL & GAS COMPANY	Mackie #1 Mackie #2 Mathers #1 Mathers #2 Bednorz #1 Bednorz #2 Bednorz #3 Bednorz #4 Bednorz #6
28. TRI-EX OIL & GAS INC.	Culbertson 1-6 Culbertson 2-6 Culbertson 3-6 Culbertson 4-6 Culbertson 5-6 Culbertson 7-6 Culbertson 8-6
29. Virgil Hess, d/b/a TUMBLEWEEK PRODUCTION CO.	Linda #3 Linda #4 Haiduk #1 Haiduk #2
30. VANDERBURG EXPLORATION INC.	Sandy #1 Sandy #2 Vandy #1[12] Vandy #2[12]
31. VANDERBURG PRODUCTION,	Vanderburg #1

INC.	Vanderburg #2
32. WALKER OPERATING CORPORATION	Burger #1 O'Neal #1 O'Neal #3 O'Neal #4 Sargent #1 Sargent #3 Sargent #4
33. BOB WALLACE OIL, INC.	Hays Trust 1-7 Hays Trust 2-7 Hays Trust 3-7 Hays Trust 4-7 Hays Trust 5A-7 Hays Trust 6-7 Hays Trust 7-7 Hays Trust 8-7
34. J.B. WATKINS	Bell #2 Bell #3 Bell #4 Bell #5 Bell #6 Bell #7 Bell #8 Bell #9 Bell A #1 Bell A #3 Bell B #1
35. WY-VEL CORPORATION	Weinheimer #1 Weinheimer #2 Patrick #1 Hodges #1 Hodges #2 Coffee #1 Dennis #1

	Cobb #1 Cobb #2
36. ZENA-B OIL & GAS, INC.	Ginn #1 Ginn #2
37. 3 W OIL, INC.	Arkie-Bill #1 Arkie-Bill "A" #3 Tieman #1 Tieman #2 Tieman #3 Tieman #4

SOURCE: Show Cause Order, Appendix A (26 FERC 61,207).

FOOTNOTES

4 Formerly the Bell #1A operated by Judy Oil Company.

7 Now Columbia #H-1, formerly Haiduk "A" #2.

8 Now Columbia #H-2.

10 Formerly Haiduk "A" #3 (Kaari Oil Company).

11 Formerly Haiduk "A" #4 (Kaari Oil Company).

12 Formerly the Vanderburg Lease wells operated by Stowers Oil & Gas Company.

APPENDIX B
PRODUCER GROUP
WELLS NOT IN THE BROWN DOLOMITE

Respondent	Well Name
Aspen	Harris No. 1 Harris No. 6
Caprock Engineers	Zack No. 1
Harlow Corp.	Beavers No. 3 Beavers No. 4
Komanche Oil & Gas	Cobb No. 3 Cobb No. 5
Raven Energy	Jeanne No. 1 Snapp No. 4
Stowers Oil & Gas	Mackie No. 2 Mathers No. 2 Bednorz A No. 2 Bednorz B No. 3 Bednorz B No. 6
Wy-Vel Corp.	Coffee No. 1 Hodges No. 2
Kaari Oil	Columbia No. 1-3 Future No. 3 Future No. 1-5

SOURCE: Exhibit 1A as modified by Exhibit 104 at 54-55.

APPENDIX C

Study Area	Dorchester Well
1 (Exhibit 104 at 23-35, Exhibits 35, 111-114)	McConnell No. 4 (Section 46, Block 4, I&GN RR Survey Carson Country

Respondent's Well	Completion Date
Prairie Alley No. 2	1982

Evidence

Dorchester's well is perforated in the brown dolomite. Respondent's well is perforated in the brown dolomite and granite wash. Pressure versus cumulative production of Dorchester's well fell sharply in 1982 when respondent's well began gas production. When production began the Prairie Alley lease was producing about 300 barrels of oil and 1,100 Mcf of gas per month and has a gas-oil ratio of 3,775 cubic feet of gas to 1 barrel of oil. In December 1983 the lease produced 35 barrels of oil and 3,300 Mcf of gas for a gas-oil ratio of 94,400 cubic feet of gas to 1 barrel of oil. The brown dolomite has no structural relief and the formation is continuous throughout the study area. Wells on the lease adjacent to Dorchester's gas well proration unit are completed in the granite wash and have no gas production. Prairie Alley lease does not have a gas processing unit.

Conclusion

Significant gas volumes produced by respondent's well are from the brown dolomite. Pressure reduction in Dorchester's well is due to respondent's gas production which is evidence of drainage. Respondent is producing gas that would have been produced from Dorchester's well. Respondent's liquid production is crude oil which is not from the brown dolomite formation. Support for this conclusion is found in the fact that Dorchester well completed in the brown dolomite produces no crude oil and the brown dolomite formaton is continuous with little structural relief. Almost all respondent's gas production is not casinghead gas, i.e., gas which is indigenous to an oil stratum and is produced from the stratum with oil. Respondent's well is draining portion of the reservoir underlying the Dorchester acreage and it is not necessary for effective or efficient drainage that it do so.

Study Area	**Dorchester Well**
2 (Exhibit 104 at 35-46, Exhibit 36, 115-117)	Beavers No. 1 (Section 117, Block B-2, H&GN RR Survey, Gray Country
Respondent's Well	**Completion Date**
Harlow Corp. Beavers Nos. 1-4	1980-1982

Evidence

Form W-2 shows only perforations for the Harlow wells in the granite wash. Stipulated that additional perforations made in 1981 in the No. 1 well in the brown dolomite and just below the granite wash marker, and in the No. 2 well in the brown dolomite and granite wash. No gas processing unit on the lease.

The month when perforations made in the brown dolomite (October 1981) gas-oil ratio for the lease went from 22,000 to 1, to 82,500 to 1, and the following month it was 137,000 to 1. Pressure versus cumulative gas production shows a regular linear trend line from 1966 until prior to 1984. Brown dolomite formaton in the area is of uniform thickness with little structural relief.

Conclusion

Gas-oil contact is at approximately 183 feet above sea level (Exhibit 264 at 14). Lease is producing significant gas volumes from the brown dolomite formation. Withdrawal of these volumes is responsible for the sharper decline in pressure shown on pressure versus cumulative production trend for the Dorchester well after 1983. Reason to blame the Harlow wells and not other area wells is that they are close to Dorchester's wells, and the pressure versus cumulative production decline curve of the Dorchester well did not change until after Harlow wells perforated the brown dolomite. Sage Petroleum Company Beavers lease on the same section as the Dorchester well is completed in grante wash formation in an interval overlapping the Harlow wells' producing interval and produces no gas. Gas produced from Harlow Beaver Nos. 1 and 2 wells is not casinghead gas, *i.e.*, not indigenous to an oil stratum and produced with oil, and is the same gas the would

have been and would be produced from the Dorchester well. Respondent's wells are draining the portion of the reservoir which would otherwise be drained by the Dorchester well, and they are not necessary to effectively and efficiently drain the reservoir. Small amount of liquid attributable to respondent's lease is probably crude oil which is not from the brown dolomite.

Study Area	**Dorchester Well**
3 (Exhibit 104 at 46-73, Exhibits 37, 38, 39, 118-127)	Bednorz No. 1 and Cobb No. 1 (Sections 183, 184 and 203 of Block 3, I&GN RR Survey, Gray and Carson Counties

Respondent's Wells	**Completion Date**
Stowers Bednorz Nos. A-1, A-2 B-3, B-4 and B-6	1980 1982
Wy-Vel Cobb Nos. 1 and 2	1980-81
Almac Bucket Shop Nos. 1 and 2	1982
Komanche Cobb Nos. 1, 2, 4 and 5	

Evidence

Brown dolomite formation is relatively flat and continuous. Form W-2 for Stowers Bednorz No. A-1 and No. B-4 show completions in the granite wash but additional completions have been made in brown dolomite. Almac Bucket Show Nos. 1 and 2, Komanche Cobb Nos. 1, 2 and 4, Wy-Vel Cobb Nos. 1 (probable) and 2 also perforated in brown dolomite as well as granite wash. Substantial gas production from the Almac Bucket Shop, Komanche Cobb, Stowers Bednorz A and B and Wy-Vel Cobb leases. ARCO Oil and Gas Company well located just south of Dorchester Bednorz No. 1 well and the Stowers Bednorz wells, and Mobil Producing Texas and New Mexico well located 600 feet south of the Komanche Cobb wells are completed only in granite wash and produce negligible amounts of gas. Pressure versus cumulative production graph for Dorchester Cobb No. 1 was quite linear for 1966 through 1977. Marked decline in pressure after 1977 when Komanche Cobb lease, Wy-Vel Cobb lease, and Almac Bucket Shop wells increased area gas production. Wy-Vel Cobb lease has a gas processing unit. Pressure versus cumulative production graph for Dorchester Bednorz No. 1 was linear from 1973 through 1977 with a marked departure from prior trend after 1977.

Conclusion

Respondents' gas production is from the brown dolomite. Conclusion supported by fact that ARCO and Mobil Oil wells completed only in the granite wash produce negligibl amounts of gas. The market departure from the pressure versus cumulative production trend for the Dorchester Bednorz No. 1 aqnd Cobb No. 1 wells was caused by respondents' gas production. Reduction in pressure is evidence of

drainage from Dorchester's wells to respondent's leases. Respondents are producing gas that would have been and would be produced from the Dorchester wells. Liquid produced on all but the Wy-Vel Cobb lease is oil not produced from the brown dolomite. Little, if any, of the liquid produced from Wy-Vel Cobb lease is oil as demonstrated by hydrocarbon analyses of outlet liqid of gas processing units. Small oil volume is not producd from the brown dolomite. Respondents' gas production is not casinghead gas because it is not indigenous to an oil stratum and is not produced from the stratum with oil. Respondents' wells are draining the portion of the reservoir that would otherwise be drained by the two Dorchester wells. Respondents' wells are not necessary to effectively and efficiently drain this portion of the reservoir.

Study Area	**Dorchester Well**
4 (Exhibit 104 at 63-73, Exhibits 40, 128-132)	Wilson-Hart No. 1 (Section 176, 177, 184 and 185, Block 3, I&GN RR Survey, Gray County
Respondent's Wells	**Completion Date**
Lear Oil & Gas, Inc., Sandra No. 1	1983
Panstar Oil & Gas Inc. Hildreth Nos. 1 and 2	1983

Dennis Mills 1982-
Enterprises, Inc. 1983
Heidi Nos. 3 and 4

Evidence

Brown dolomite formation is relatively flat and uniformly thick, W-2's show completion in brown dolomite for Sandra No. 1 and Heidi No. 3. Stipulated that Heidi No. 4, Panstar Nos. 1 and 2 also perforated in brown dolomite. The Dennis Mills Heidi lease and te Panstar Hildreth leases have gas processing units. Dorchester will procued average of 24 Mcf per day in 1983, when the Hildreth and Heidi leases had a per well average of 165 Mcf. Dorchester well shows a departure from the historical trend line in 1982 and 1983 when Dennis Mills Heidi lease and Panstar Hildreth lease began producing gas.

Conclusions

Respondents' five wells are producing significant gas volumes from the brown dolomite; this gas is the ame gas that otherwise would have been and would be produced from the Dorchester Well. Decline in pressure of the Dorchester well due to drainage by Hildreth Nos. 1 and 2 and Heidi Nos. 3 and 4. More than likely liquid produced from the Lear Sandra lease is oil not from the brown dolomite, but little, if any, liquid produced from the Heidi and Hilbreth leases is oil. Because the brown dolomite formation is continous other wells completed in the same producing level should have the same results. Respondents' wells are not producing casinghead gas because gas is coming from the brown dolomite and oil is not, so gas is not indigenous to an oil stratum and produced from that stratum with oil. Respondents' wells are not necessary to effectively and

efficiently drain that portion of the reservoir which is drained by the Dorchester well.

Study Area	**Dorchester Well**
5 (Exhibit 104 at 73-92, Exhibits 41, 42, 43, 133-142	Warren No. 1 Durrett No. 1 Pickens No. 1 (Sections 6, 7 16 and 17 Block 7, and Sections 6 and 7, Block 4, I&GN RR Survey, Carson County)

Respondent's Wells	**Completion Date**
Tri-Ex Oil Gas Culbertson Nos. 1-6, 2-6,3-6, 4-6, 5-6, 7-6, and 8-6	1981, 1982
Tri-Ex Oil & Gas Hays Trust Nos. 1-7, 2-7, 3-7, 4-7, 5A-7,6-7, 7-7 and 8-7	1981, 1982
Lucky Bird Petroleum Thornburg Nos. 3-6	1980-1982

Evidence

Brown dolomite has uniform thickness of about 200 feet, little structural relief except an 80 foot dip near Dorchester Pickens No. 1. Dorchester Warren No. 1

had a linear pressure versus cumulative gas production trend from 1977 until 1982 when wellhead shut in pressure began to decline more rapidly. Dorchester Durrett No. 1 shows linear trend of pressure versus cumulative production from 1966 to 1976 when it was fracture treated. From 1982 pressure declined more rapidly than would be expected. Dorchester Pickets No. 1 shows rather linear trend of pressure versus cumulative gas production from 1966 through 1980. Pressure drop accelerated after 1980. Contrary to information on W-2 forms, parties stipulate that respondents' wells were completed in brown dolomite, except Culbertson No. 6-6 which was plugged and abandoned. Culbertson, Hays Trust, and Thornburg leases have gas processing units. Each of the Culbertson wells average some 200 Mcf per day in 1983 when Dorchester Warren No. 1 produced a daily average of 144 Mcf. Each of eight wells on the Hays Trust lease produced approximately 120 Mcf per day in 1983, when Dorchester Durrett produced a daily average of 170 Mcf. The Lucky Bird Thornburg lease increased gas production substantially when No. 3 well completed. Lucky Bird Thornburg lease averaged 153 Mcf per well in 1983 compared to Dorchester's Pickens No. 1 well of 76 Mcf per day. Phillips Petroleum Thornburg lease, five wells in the southwest quarter of the section not perforated in the brown dolomite, produces very little gas. Its gas-oil ratio has ranged from 839 to 5,100 cubic feet of gas per barrel of stock tank liquid from 1970 through February 1984.

Conclusion

Respondents' wells are producing significant gas volumes from the brown dolomite. Evidence includes: completions in this formation, their high gas-oil ratios, and the change in the pressure versus cumulative production trend of Dorchester's three wells which

coincides with significant gas production from respondents' wells. Respondents' wells are producing gas that otherwise would have beenor would be produced from Dorchester wells on whose proration units respondents' wells are situated. Little, if any, of the liquid produced on respondents' leases is oil and what is oil is not produced from the brown dolomite. Dorchester's wells completed only in brown dolomite do not produce any oil. Respondents' gas production is not casinghead gas.

Study Area	**Dorchester Well**
6 (Exhibit 104 at 92-109, Exhibits 44, 45, 46, 143-157)	Bryan No. 1 Haiduk No. 1 (Section 1, 2 21 and 22, Block 4, I&GN RR Survey Carson County

Respondent's Wells	**Completion Date**
Kaari Oil Co. Haiduk, D Nos. 2-18 & 4-22	1983
Ezekiel Energy Kelly Nos. 1-1, and 1-2	1982
Kaari Oil Co. Columbia Nos. 1-3, 2-4, H-1 and H-2 and Haiduk C Nos. 1-13 and 2-14	1982-1983

Raven Energy, Inc., Martha Nos. 1, 2	1982-1983
Tumble Weed Production Co. Haiduk Nos. 1 and 2	1982

Evidence

Brown dolomite is flat, uniformly thick with little structural relief. Several non-respondent leases located near Dorchester's Bryan No. 1 well have very high gas-oil ratios. Trend of pressure versus cumulative production graphs for Dorchester Bryan No. 1 and Dorchester's Haiduk No. 1 were linear prior to 1975, with increasing downward slope between 1975 and 1981 and sharp drop in 1981 and 1982. In 1975 Natural Gas Pipeline Bednorz No. T-1 well located on Dorchester proration unit immediately south of Dorchester's Haiduk No. 1 proration unit substantially increased gas production. Respondents' leases and several non-respondent leases in study area 6 have high producing gas-oil ratios. Gas-oil ratio for the Kaari Oil Company Haiduk D lease ranged from 8 to 99,925 cubic feet of gas per barrel of stock tank liquid. All respondents' leases are equipped with gas processing units and all respondents' wells are perforated in the brown dolomite as well as the granite wash.

Conclusions

Production in 1975 from Natural Gas Pipeline Co. J.H. Ubanozyk No. L-2 gas well and production from respondents' wells and non-respondents' wells in 1982 and 1983 caused the trend of pressure versus cumulative production of Dorchester Bryan No. 1 to

decrease somewhat more rapidly after 1975 and much more rapidly after 1981. Steeper decline in pressure curve for the Haiduk No. 1 well after 1975 due to increased production from Natural Gas Pipeline's Bednorz No. T-1 well located in Dorchester proration unit immediately south of the Dorchester Haiduk No. 1 proration unit. Production from respondents' leases primarily responsible for the sharp decline in the Dorchester Haiduk well pressure after 1982. Fact that respondents' gas-oil ratios increased suddenly from initial low levels to very high levels indicates that after they were completed initially in the granite wash the wells were subsequently completed in and produced gas from the brown dolomite. Gas production from respondents' lease has caused a marked reduction in pressure of the Dorchester wells. Pressure drop is evidence of drainage. Gas produced from respondents' leases is the same gas that would otherwise have been and would be produced from the Dorchester wells. Liquid produced on these leases is not oil, i.e., it was not liquid in the reservoir, wellbore, and at the surface. Respondents' production is not casinghead gas. Respondents' leases within this study area drain portion of the reservoir underlying the Dorchester acreage which would otherwise be drained by the Dorchester wells.

Study Area	**Dorchester Well**
7 (Exhibit 104 at 109-123 Exhibits 47, 48, 158-166)	Walker No. 1
	White Deer Investment No. 1 (Sections 182, 183

	203, 204, and 241, Block B3, I&GN RR Survey and Block B-2, H&GN RR Survey, Carson County)
Respondent's Wells	**Completion Date**
Prairie Koell Nos. 1 & 2	1983
Prairie Steel Nos. 1 & 2	1982
WyVel Hodges Nos. 1 & 2 and Coffee No. 1	1982 & 1983

Evidence

Brown dolomite is uniformly thick and relatively flat. Pressure versus cumulative gas production trend for Dorchester's White Deer Investment No. 1 consistent 1966 to 1972, steeper slope after 1972 and again after mid-1982. Trend of pressure versus cumulative gas production linear for Dorchester Walker No. 1 from 1966 until 1974 when downward slope increased, with an extremely sharp drop in 1982. Wy-Vel Hodges No. 1 and four Prairie wells completed in brown dolomite. Wy-Vel Coffee No. 1 and Hodges No. 2 are perforated in granite wash up to the base of the brown dolomite. Wy-Vel Hodges only lease without a gas processing unit. In 1983 average daily production was 112 Mcf for Dorchester Walker No. 1, 65 Mcf for Dorchester White Deer Investment No. 1, and approximately 200 Mcf for Prairie Oil Company Steel and Koellk leases. In 1982 Dorchester Walker No. 1 produced an average of 250

Mcf per day. The 1983 drop in average daily production coincides with dramatic increase in gas-oil ratio from the Wy-Vel Hodges leases, increased gas production from the Omega Winters lease, and high gas-oil ratios from the Wy-Vel Coffee lease.

Conclusion

Change in slope of pressure trend line of Dorchester's White Deer Investmednt No. 1 after 1972 due to increased production for non-respondents, Natural Gas Pipeline McEwen No. G-1 and Omega Energy Winters lease. Change in the same line for Dorchester's Walker No. 1 due to increased production from Natural Gas Pipeline's McEwen No. G-1 after 1974 and increased production from Prairie wells on the Steel and Koell leases beginning on 1982. Significant gas volumes from Wy-Vel Hodges and Coffee leases and Prairie Koell and Steel leases are being produced from brown dolomite, causing reduced pressure in the Dorchester wells and drainage from Dorchester's wells to respondents' leases. Respondents' leases are producing gas that would have been and would be produced from the two Dorchester wells. Likely that liquid produced from Wy-Vel Hodges lease is oil. Little, if any, liquid produced from the Wy-Vel Coffee, Prairie Koell and Prairie Steel leases is oil based on hydrocarbon analyses (Exhibit 91). What oil is produced is almost certainly not from the brown dolomite. Unlikely based on structure of brown dolomite that respondents wells would produce oil when Dorchester's wells do not. Almost all gas produced by respondents' leases is not casinghead gas because it is not indigenous to an oil stratum and produced from the stratum with oil. Respondents' wells are not necessary to effectively and efficiently drain portions of the reservoir drained by the Dorchester wells.

Study Area	Dorchester Well
8 (Exhibit 104 at 124-164, Exhibits 49, 54, 167-195)	Fields No. 1 (Section 155, Block 3, I&GN RR Survey, Gray County) Fields No. 2 (Section 158; Block 3, I&GN RR Survey Gray County) Bell No. 1 (Section 156, 134, Block 3, I&GN RR Survey Gray County) Vaniman No. 1 (Section 156 & 157, Block 3, I&GN RR Survey Gray County) Benedict No. 1 (Section 133, Block 3, I&GN RR Survey)

Respondent's Wells	Completion Date
Caprock Engineers Zack Nos. 1 & 2	1983

Granite Production Dennis Nos. 1, 2 & 4	1981, 1982
Aspen Harris Nos. 1, 2, 5 & 6	1981
Aspen Fields Nos. 3, 4, 7 & 8	1981
Raven Energy Jeanne Nos. 1 & 2	1982
Caddo Production Co. Faith No. 1	1981
Jody Oil Company Lloyd Nos. 2 & 3	1981 &
Panhandle Energy Alley Nos. 1 & 2	1982
Panhandle Energy Wade L No. 1	1983
Judy Oil Company Boddy Nos. 1 & 2	1981
Walker Operating Corp. O'Neal Nos. 1, 3, & 4 (Coddo Faith No. 2A and O'Neal No. 2 recently completed but are not listed in Show Cause order)	1983
Kaari Future B Nos. 1-15 & 2-16	1983
Walker Sargent Nos. 1, 3 & 4	1983
Walker Burger No. 1	1983
Bink Ann Nos. 1 & 2	

Raven Energy Snapp
No. 1 & 4
Kaari Future Nos.
1-5, 2-6, 3 & 4
Kaari Randall Nos.
1 & 2 (incorporated
into future lease 11/83)

Evidence

Brown dolomite continuous with little structural relief except slight dip from northeast to the southwest. All respondents' wells except Aspen Harris Nos. 1 and 6, Raven Jeanne No. 1, Caprock Zack No. 1, Kaari Future Nos. 3 & 1-5, and Raven Snapp No. 4 are open to production in the brown dolomite. Pressure versus cumulative gas production for Dorchester's Fields No. 2 was reasonably linear from 1966 through 1972, linear with a steeper slope from 1973 through 1981, and sudden drop in 1982-1984. Aspen Petroleum Fields lease and Aspen Petroleum Harris lease increased gas-oil ratio suddenly and substantially in January and February 1982. The gas-oil ratio for the Raven Energy Jeanne lease increased suddenly and substantially in October 1982. None of these leases have gas processing units. Wellhead pressure versus cumulative production for Dorchester Fiels No. 1 well shows reasonably linear trend from 1966 through 1982, with faster pressure drops after 1982. The gas-oil ratio for the Granite Production Dennis lease increased substantially in late 1982. The Caprock Zack lease showed initial gas-oil ratio of 613 for the No. 1 well and a gas volume too small to measure for the No. 2 well. Between 8/83 and 12/83 the gas-oil ratio for the lease was between 39,000 and 99,000 cubic feet of gas per barrel of oil. None of the leases on these two Dorchester proration units have gas processing facilities. Mobil well, adjacent to Dorchester Fields No. 1 production unit, completed in

the granite wash in 1983 has produced no gas. Pressure versus cumulative production trend line for Dorchester Bell No. 1 was reasonably linear from 1967 through 1977 and 1978 through 1981, with severe drop in 1982. Jody Oil Company Boddy and Bell leases have gas processing units. All the leases on the Dorchester Bell No. 1 proration unit has high gas-oil ratios in 1983 ranging from 20,600 to 101,621 cubic feet of gas per barrel of oil each month. Pressure versus cumulative gas production was reasonably linear for Dorchester Vaniman No. 1 from 1967 through 1974 and 1976 through 1981 with a rapid pressure decrease thereafter. Pressure versus cumulative production trend for Benedict No. 1 was linear from 1967 through 1973 and from 1974 until 1982. The slope of the trend line increased in 1974. From 1982 through May 1984 wellhead shut-in pressure dropped dramatically. Respondents' wells on Benedict No. 1 proration unit have high gas-oil ratios.

Conclusion

Dorchester Fields No. 2--Respondents' leases on the Dorchester Fields No. 2 proration unit have cause sudden pressure drop in the Dorchester well beginning in 1981. Reduction evidences drainage from the Dorchester well. Respondents' gas production is gas that would otherwise have been and would be produced from Dorchester Fields No. 2 well. Respondents' leases on Dorchester Fields No. 1 proration unit and 3 wells on adjoining Judy Oil Company lease caused rapid decrease in wellhead pressure of Dorchester Fields No. 1 after 1982.

Dorchester Fields No. 1--Gas production from the Granite Dennis and Caprock Zack leases caused the pressure reduction in Dorchester Fields No. 1 well. This pressure reduction is evidence of drainage.

Respondents' leases are producing same gas that otherwise would have been and would be produced from the Dorchester Fields No. 1 well.

Dorchester Bell No. 1--Sharp decline in wellhead pressure in 1982 through 1984 in Dorchester Bell No. 1 due to gas production on respondents' leases as well as from production from Caddo Production Faith lease, the Panhandle Energy Wade L lease and the Walker Operating Corp. O'Neal lease. Pressure decline in 1977 due to increased production from the offsetting Conoco Bell lease. Respondents' gas production contributed substantially to marked reduction in Dorchester well. Pressure reduction evidences drainage from Dorchester well. Respondents are producing the same gas that would otherwise be produced by Dorchester well.

Dorchester Vaniman No. 1--Loss of wellhead pressure du to respondents' gas production from wells on this and other Dorchester proration units. Respondent Kaari Future B lease, with a gas-oil ratio in November 1983 of 60,000 cubic feet of gas per barrel of oil, contributed significantly to the drop in wellhead pressure of Dorchester's well in 1983.

Dorchester Benedict No. 1--Slight slope change of the pressure versus cumulative production trend line in 1974 due to production increase of Conoco Case No. 1 gas well. Pressure drops due to respondents' gas production on this Dorchester proration unit and perhaps respondents' production from wells located on eastern boundary of Section 156. Pressure drop is evidence of drainage from the Dorchester well to respondents' leases. Respondents' gas production is the same gas that otherwise would have been and would be produced from the Dorchestr Benedict No. 1 well. Liquid attributed to these leases without processing units probably is crude oil. Almost certainly this crude

oil is not being produced from the brown dolomite based on Dorchester's experience. Most of the liquids from leases with processing units is not oil based on hydrocarbon analyses. Small amount that is oil is not from the brown dolomite. Respondents' gas is not casinghead gas because it is not indigenous to an oil stratum and produced from that stratum with oil.

Study Area	**Dorchester Well**
9 (Exhibit 104 at 165-172, Exhibits 55, 196-200)	Osborne No. 2 (Sections 108 & 109. Block 3, I&GN RR Survey, Gray County)
Respondent's Wells	**Completion Date**
3-W OIL, Inc. Arkie - Bill A No. 3 & No. 1	1982

Evidence

Brown dolomite approximately 175 feet thick and dips gently to the northeast. Respondents' wells completed in the brown dolomite. Producing interval of Dorchester well and respondents' wells overlap. Pressure versus cumulative gas production of the Dorchester well shows a linear decline in pressure from 1966 through 1981 with departure thereafter. In 1983 respondents' two wells had gas-oil ratios ranging from 40,000 to 90,000 cubic feet per barrel of liquid. One gas processing unit serves both leases. When tested for production potential, both wells showed very little gas

production when perforated only in the granite wash as shown in form W-2s.

Conclusion

Decline in pressure of the Dorchester well in 1982 primarily caused by production from the Arkie-Bill leases. Drop in pressure of the Dorchester well indicates drainage by respondents' wells. Fact that Dorchester's wells perforated in brown dolomite, use of gas processing unit, high gas-oil ratios, and low gas production when perforated only in granite wash indicates that almost all the gas produced from these leases comes from the brown dolomite and is therefore gas which otherwise would be produced by Dorchester's Osborne No. 2. Little, if any, of the liquid produced by respondents' wells is oil based on hydrocarbon analyses. Little liquid that may be oil is almost certainly not from the brown dolomite based on Dorchester's experience and structure of the brown dolomite. Respondents' gas is not casinghead gas because it is not indigenous to an oil stratum and produced from that stratum with oil. Respondents' wells drain the portion of the reservoir underlying the Dorchester acreage which the Dorchester well would drain, and they are not necessary to effectively and efficiently drain that portion of the reservoir.

Study Area	**Dorchester Well**
10 (Exhibit 104 at 173-187, Exhibits 56, 57, 200-210	Witter No. 1-A Witter No. 2

Respondent's Wells	Completion Date
Magnet Oil Inc. Dania No. 3	1982
Tumble Weed Linda Nos. 3 & 4	1982
Energy-Agri Products, Inc. Money Nos. 1 & 2, Peeler II No. 1, Peeler Nos. 2-4, and Henry Nos. 1-4	1981, 1982 1983

Evidence

In the area near Dorchester's Witter Nos. 1-A and 2 wells, the brown dolomite varies slightly in thickness but has little structural relief. In the area near Dorchester's Pope No. 1 the brown dolomite is of uniform thickness with a gentle structural dip to the southeast. All respondents' wells perforated in the brown dolomite. Pressure versus cumulative production from 1966 to May 1984 for the Dorchester Witter No. 1 shows increased downward slope after 1974, reasonably linear trend from 1975 until 1982 when it dropped sharply. Gas-oil ratios for respondent's Dania leases have gas processing units. Pressure versus cumulative production for the Witter No. 2 from 1966 was reasonably linear until 1981 and 1982 when the pressure trend flattened. Monthly gas-oil ratio for Linda lease ranged from 30,000 to almost 80,000 cubic feet per barrel. Pressure versus cumulative production trend for Dorchester Pope No. 11 linear from 1966 until 1983; pressure fell dramatically in 1984. Stock tank liquid from the Magnet Dania lease and Energy-Agri

leases contain almost no oil. Wellhead liquid sample from Energy-Agri Money lease 100 percent water. The three Energy-Agri leases have extremely high gas-oil ratios.

Conclusion

Dorchester Witter No. 1-A--Two non-respondent wells may have caused increase in downward slope of pressure versus cumulative production graph after 1974. Dania No. 3 well largely responsible for the very rapid decline in pressure from 1982 forward. Respondent's lease producing same gas that Dorchester well would produced.

Dorchester Witter No. 2--Flattened pressure trend in 1981 and 1982 due to decreased production from Natural Gas Pipeline's Mauldin No. 1E well and treatment of Dorchester well in 1978 and 1979. Production from Tumble Weed Linda Nos. 3 & 4 will result ultimately in a significant decline in pressure of the Dorchester well. Respondent's producing the same gas that would otherwise be produced by Dorchester well.

Dorchester Pope No. 1--Dramatic drop in well pressure in 1984 due to dense development on leases surroundng the Dorchester well by Energy-Agri Products, Inc. Respondent's wells have higher gas-oil ratios than can be expected from oil wells located in an area producing gas only from the granite wash. Respondent is producing gas that otherwise would be produced by Dorchester well.

Very little, if any, liquid produced from respondents' leases is oil. Small amount of liquid which may be oil is almost certainly not produced from the brown dolomite. Based on Dorchester's experience and structure of

brown dolomite formation, highly unlikely that respondents' oil production comes from brown dolomite. Respondentssss' gas production is not casinghead gas because it is not indigenous to an oil stratum and produced from that stratum with oil. Respondents' wells drain the Dorchester wells and they are not necessary to effectively and efficiently drain the portions of the reservoir drained by the Dorchester wells.

Study Area	**Dorchester Well**
11	Bell No. 2
(Exhibit 104 at 187-208, Exhibits 58-62, 211-227)	Bell No. 3
	Case No. 1
	Chadwick No. 1
Mongole No. 1 (Sections 181, 182, 183, 208, 209, 210, 211, 238 and 240, Block B-2, H&GN RR Survey and Section 130, Block 3, I&GN Survey, Gray and Carson Counties)	

Respondent's Wells	**Completion Date**
Aspen Petroleum, Inc., Bell Nos. 1 & 3	1981
J.B. Watkins Bell Nos. 2-9, Bell A nos. 1 and 3 1981	1978, 1979, 1980,
3-W Oil, Inc Tieman Nos. 1-4	1981, 1982, 1983
Apen Petroleum, Inc. Warnick Nos. 1-4, Chadwick Nos. 7-9	1981
Wy-Vel Corp. Dennis No. 1	1982

Evidence

Brown dolomite formation is continous with uniform 200 foot thickness and little structural relief except in Watkins Bell and Aspen Bell leases. Brown dolomite encountered by wells on Watkins Bell and Bell A leases at approximately 475 feet above sea level and at about 750 feet above sea level in each of respondents' other wells. Dorchester Chadwick No. 1 originally drilled through brown dolomite into granite wash where there was a show of oil. Well was plugged back to granite wash marker. Pressure versus cumulative production curves for 1966 through April 1984 for the Dorchester wells are as follows:

Bell No. 2--reasonably linear 1966 to 1982, precipitous decline thereafter,

Bell No. 3--smooth decline until 1982, drastic decline thereafter,

Case No. 1--rather linear until 1978 when well treated and production improved, increased downward slope 1982-1984,

Chadwick No. 1 and
Mongole No. 1--pressure declined more rapidly beginning in 1982.

All respondents' wells are open in the brown dolomite. All leases except for watkins' Bell and Bell A have gas processing units. All respondents' leases have had gas-oil ratios from 40,000 cubic feet of gas and higher to one barrel of oil.

Conclusions

Significant volumes of respondents' gas production is from the brown dolomite based on the fact that all respondents' wells are perforated in the brown dolomite, they produce substantial gas volumes at high gas-oil ratios, and Dorchester's wells within whose proration units respondents' wells are located have had marked declines in their pressure versus cumulative gas production trends. Pressure declines are explained by respondents' production and for Dorchester's Mongole No. 1 well gas production from offsetting non-respondent leases. Based on hydrocarbon analyses of liquid from processing unit on the Aspen Jones, Chadwick and Warnick leases, the liquid from 3-W Oil Tieman and the Wy-Vel Dennis leases is not oil. Outlet liquid from processing unit on Aspen Bell lease is probably not oil. Small amount of liquid from these

leases which may be oil is almost certainly not fromthe brown dolomite based on Dorchester's experience and the continuous structure of the brown dolomite. Respondents' wells, except for Watkins, are not producing casinghead gas because it is not indigenous to an oil strtum and produced from the stratum with oil. Respondents' wells are draining portions of the reservoir underlying Dorchester acreage that would otherwise be drained by Dorchester wells. Respondents' wells are not necessary to effectively and efficiently drain this portion of the reservoir. Based on proximity of Watkins leases to an old oil producing area of the field, the low structure of the brown dolomite, and the shape of the phase envelope for the wellhead gas from Watkins' Bell A No. 1, quite possible tht Watkins wells are producing oil from the brown dolomite. Tentatively conclude that although it is possible that oil is being produced from the brown dolomite, not all gas from Watkins wells is produced with tht oil. Reasons are that Bell and Bell A leases have high gas-oil ratios and that the shape of the phase envelope for the gas from the Bell A No. 1 well is somewhat different than the phase diagram for a well producing only casinghead gas.

Study Area	**Dorchester Well**
12 (Exhibit 104 at 209-216, Exhibits 63, 228-230)	Evans No. 1 (Section 153, Block B-2, H&GN RR Survey, Gray County)

Respondent's Wells	Completion Date
Security Petroleum Evans Nos. 1, 4, 6, 7 & 8	1981

Evidence

Brown dolomite is of uniform thickness but appears about 85 feet higher in the Dorchester well than in respondents' wells. Evidence is that the brown dolomite drops slightly form north to south in this area. All respondent's wells perforated in the brown dolomite at levels corresponding to open hole completion interval of Dorchester well. Pressure versus cumulative production curve for the Dorchester well rather linear curve from 1966 through 1979. Well treated with hydraulic fracture in late 1978. Pressure and production improved in 1980, erratic movement of curve from 1980 to 1984. In 1982 and 1983 respondent's lease, which has a gas processing unit, has had substantial gas production and gas-oil ratios of from 41,500 to 85,000 Mcf per barrel of liquid.

Conclusion

Treatment (hydraulic fracture) of Dorchester well in November 1978 caused improved production and pressure to offset whatever impact respondents' wells might have had. Expect that Dorchester well will be affected as respondent's wells continue significant gas production. Respondent's gas production comes from the brown dolomite and is the same gas that would otherwise be or hav been produced by Dorchester well. Conclusion is based on perforations in the brown dolomite, high gas-oil ratios with substantial gas production, and existence of a gas processing unit.

Based on hydrocarbon analyses of the outlet liquid of gas processing units, the liquis manufactured from such units are not oil, therefore respondent's liquid probably is not oil. The small amount of liquid that may be oil is almost certainly not produced from the brown dolomite. Dorchester's wells perforated only in the brown dolomite produce no oil, and the formation is not sufficiently different to expect a different result in respondent's wells. Almost all respondent's gas is not casinghead gas because it is not indigenous to an oil stratum and produced from that stratum with oil. Respondent's wells are draining that portion of the reservoir which would otherwise be drained by the Dorchester well, and it is not necessary for effectiveness and efficiency that they do so.

Study Area	**Dorchester Well**
13 (Exhibit 104 at 216-223, Exhibits 64, 231-234)	McBrayer No. 1 (Sections 69, 63, Block 7, I&GN RR Survey, Carson County)
Respondent's Wells	**Completion Date**
Wy-Vel Corp. Patrick No. 1 and Weinheimer Nos. 1 & 2	1981

Evidence

Brown dolomite is of uniform thickness with little structural relief. Pressure versus cumulative

production curve for Dorchester well shows irregular downward trend from 1966 through 1976. All respondent's wells are perforated in the brown dolomite. In 1982 after respondent's wells were completed the Dorchester well was treated (cleaned out and acidized) which increased bottom-hole pressure. In 1982 and 1983 respondent's Patrick lease produced monthly between 3,500 and 10,132 Mcf of gas with gas-oil ratios as high as 100,000, and the Weinheimer lease produced monthly between 3,900 and 14,900 Mcf with gas-oil ratios as high as 99,900 cubic feet per barrel. Dorchester well averaged 23 Mcf per day in 1983 while Weinheimer lease averaged 74 Mcf and Patrick lease averaged 147 Mcf per day.

Conclusion

Unclear from pressure versus cumulative gas production graph whether respondent's wells are causing significant drainage from Dorchester well; however, it is expected that such will occur. Significant volumes of respondent's gas production is from the brown dolomite. Weinheimer No. 1 is only open in this formation, and respondent's other wells are open in the brown dolomite and the granite wash. Liquids being produced by responent's are not from the brown dolomite based on Dorchester's experience and uniformity of brown dolomite formation. Respondent's gas production is not casinghead gas because respondent's production is almost all from the brown dolomite. Because the oil produced is not from the brown dolomite, the gas is not indigenous to an oil stratum and produced from that stratum with oil. Respondent's wells are draining gas from that portion of the reservoir underlying the Dorchester acreage. Dorchester would otherwise produce this gas. Respondent's wells are not necessary to effectively and efficiently drain this portion of the reservoir.

Study Area	Dorchester Well
14 (Exhibit 104 at 224-233, Exhibits 65, 235-239)	Sheridan No. 3 (Section 206, Block B-2, H&GN RR Survey, Gray County)
Respondent's Wells	**Completion Date**
A&R Operting Co. (formerly Kim Petroleum) Sheridan Nos. 1 & 2	1981
Aspen Petroleum Sheridan Nos. 2, 4, 7 & 8	1981
Security Petroleum Sheridan Nos. 2 & 4	1980

Evidence

Brown dolomite is continous and varies 50 feet in thickness and elevation (structural relief). All respondents' wells are perforated in the brown dolomite. Pressure versus cumulative gas production graph for the Dorchester well shows linear relationship from 1968 to 1981 with faster pressure decline thereafter. Each of respondents' leases produces substantial quantities of gas at gas-oil ratios generally ranging from 20,000 to 90,000 cubic feet of gas per

barrel of oil. The Aspen Petroleum lease has a gas processing unit.

Conclusion

Significant volumes of respondents' gas come from brown dolomite. Sharp decline in pressure of the Dorchester well beginning in 1981 due to respondents' gas production. Reasons are that respondents' wells are ope in the brown dolomite and have completion intervals that overlap those of the Dorchester well. Also, Aspen Sheridan Nos. 2 & 4 produced little gas when they were open only in the granite wash. Respondents' wells are producing and have produced gas that would otherwise be produced by the Dorchester well. Liquid produced from the A & R Sheridan and Security Petroleum leases is not from brown dolomite. Little, if any, of the liquid produced from the Apen Sheridan lease is oil based on hydrocarbon analysis of outlet liquid of gas processing units. Small amount of liquid that is oil is almost certainly not from the brown dolomite. Reasons are that Dorchester's well does not produce oil from the brown dolomite and formation is continuous without substantial structural relief. Almost all respondents' gas is not casinghead gas because it is not indigenous to an oil stratum and produced from the stratum with oil. Respondents are draining portion of the reservoir which would be drained by the Dorchester well. Respondents' wells are not necessary to effectively and efficiently drain that portion of the reservoir.

Study Area	**Dorchester Well**
15 No. 1	Coffee (Sections 15

(Exhibit 104 at 233-240, Exhibits 66, 240-242)	& 16, Block 4, I&FN RR Survey, Carson County)
Respondent's Wells	**Completion Date**
Meyer Farms Coffee Nos. 1, 2, & 3	1964, 1967, 1981

Evidence

Pressure versus cumulative production graph for Dorchester well from 1966 through April 1984 is linear, which is typical for a gas well operating under normal circumstances. Slope of the curve increases after 1971. Meyer Farms Coffee and Crutchfield leases shut-in from 1976 to 1981. Dorchester well treated in 1978 and pressure decline curve flattened after that. According to well records and W-2s filed with the Railroad Commission respondent's wells only perforated in the granite wash. Respondent's lease does not have a gas processing unit.

Substantial gas production began in 1981. Meyer Farms Coffee lease has produced about 200,000 Mcf of gas since 1981. In 1982 and 1983 the monthly gas-oil ratio was consistently above 72,000 Mcf of gas per barrel of oil, typically 80,000 to 90,000 cubic feet per barrel. Stock tank liquid production in 1982 and 1983 averaged about 1,100 barrels a year.

Conclusion

Accelerated pressure drop in Dorchester well after 1971 due to production by Natural Gas Pipeline No. 3-

T Crutchfield, Natural Gas Pipeline No. 1-T Crutchfield, and possibly by Meyer Farms Coffee and Crutchfield leases. Respondent's wells may be producing gas from the brown dolomite since other wells examined that are only perforated in the granite wash generally have small gas-oil ratios, 200 cubic feet or less per barrel of oil, and there is no structural variation in the brown dolomite and granite wash formations between these wells and respondent's wells. Additional persuasive evidence is that respondent does not have a gas processing unit, respondent's wells are not located in structurally low area of the brown dolomite, and wells have a high gas-oil ratio. Pressure versus cumulative production graph is not conclusive to the occurrence of drainage. If respondent's wells are perforated in the brown dolomite they could drain portions of the reservoir which would otherwise be drained by the Dorchester well. Respondent's wells are not necessary to effectively and efficiently drain that portion of the reservoir.

Study Area	**Dorchester Well**
16 (Exhibit 104 at 241-275, Exhibits 67-71,243-263	Vanderburg No. 1 (Section 113, Block B-2, H&GN RR Survey, Gray County) Pinnell No. 1 (Section 128, Block B-2, H&GN RR Survey, Gray County)

	D-114)
	Ginn No. 1 (Sections 126 & 127, Block B-2, H&GN RR Survey)
	Mathers No. 1 (Section 144, Block B-2, H&GN RR Survey, Gray County)
	Kinney No. 1 (Section 114 & 127, Block B-2, H&GN RR Survey)

Respondent's Wells	**Completion Date**
Dahalo Lease Corp. Vanderburg Nos. 1 & 2	1981
Vanderburg Exploration	
Vandy Nos. 1 & 2	1980
Vanderburg Exploration Sandy Nos. 1 & 2	1982
Almac Big Bull Nos. 1 & 2	1982
*Zena-B Oil & Gas Inc. Ginn No. 1	
*Vanderburg Exploration Sandy No. 1	1982
Sharon Lease Oil	1980,

Co. Sharon Nos. 1-4	1982, 1983
Vanderburg Production Vanderburg No. 1	1982
Dahalo Vanderburg A No. 1	1981
Omega Ginn Nos. 1-3	1980, 1981
Zena-B Ginn Nos. 1 & 2	1983
Stowers Mathers Nos. 1 & 2	1981, 1982
**Omega Energy Ginn, Nos. 1-3	
Vanderburg Production Vanderburg No. 2	1982
Stowers Mackie Nos. 1 & 2	1980

*Not on proration unit assigned to the Pinnell No. 1 but are adjacent to that unit.

**Not an proration unit assigned to the Mathers No. 1 but an adjacent section.

Evidence

Brown dolomite is relatively flat and uniformly thick with slight structural relief near Dorchester Pinnell

No. 1 and Mathers No. 1. Marked departure from the pressure versus cumulative production graph of Dorchester Vanderburg No. 1 coincided with gas production from respondents' leases. All respondents' wells perforated in the brown dolomite. Respondents' leases, except for Vanderburg Exploration Vandy, had gas processing units in May 1984. All three leases on the Dorchester Vanderburg proration unit had gas-oil ratios in the range of 90,000 cubic feet of gas to one barrel of oil from the summer of 1982 through much of 1983. In 1983 Dorchester Vanderburg well averaged 19 Mcf per day while in December 1983 respondents' wells averaged (per well) between 78 and 135 Mcf. Not apparent from pressure versus cumulative production curve that respondents' production is adversely affecting Dorchester Pinnell No. 1. The two wells on the Almac Big Bull lease are perforated in the brown dolomite and the lease has a gas processing unit. In the month these wells were completed they had initial gas-oil ratios of 688 cubic feet of gas per barrel. From July 1982 through December 1983, the gas-liquid ratio ranged from 37,000 to 99,000 cubic feet of gas per barrel. In 1983 Dorchester Pinnell produced an average of 10 Mcf daily, in December 1983 the Almac Big Bull wells averaged 119 Mcf per well daily.

Pressure versus cumulative production trend for Dorchester Ginn No. 1 showed a linear decrease from 1966 to 1981, with dramatic pressure drops in 1982-1984. Zena-B lease has gas-oil ratios in the range of 30,000 to 90,000 cubic feet per barrel; the ratios of the other leases are in the range of 80,000 to 90,000 cubic feet per barrel. From 1981 through 1983, Dorchester Ginn No. 1 produced approximately 0.1 Bcf of gas while respondents produced 1.65 Bcf. The Dorchester well averaged 10 Mcf per day in 1983, in December 1983 respondents' wells averaged 104 Mcf per day. The

Sharon, Vanderburg and Dahalo leases have gas processing units.

Linear trend of pressure versus cumulative gas production for Dorchester Mathers No. 1 for 1966 through 1980 with sharp drop thereafter. Gas-liquid ratio for the Stowers Mathers lease started out in the 200 to 500 cubic-feet per barrel range and increased rapidly to 40,000 cubic feet per barrel in September 183. The Stowers Mathers wells have produced significant gas volumes. In December 1983 these wells each averaged 28 Mcf per day. Mathers No. 1 completed in brown dolomite and granite wash. Mathers No. 2 apparently completed only in granite wash.

Pressure versus cumulative production trend for Dorchester Kinney was reasonably linear from 1966 through 1981, pressure dropped drastically in 1982, 1983 and 1984. Vanderburg Production Vanderburg No. 2 and Stowers Mackie No. 1 perforated in brown dolomite. Former lease had initial low gas-liquid ratio, less than 500 Mcf, which increased dramatically in April 1982 so as to produce at ratios averaging 90,000 cubic feet per barrel through December 1983. The Vanderburg Production Vanderburg lease has a gas processing unit. Stowers Mackie lease began with a gas-liquid ratio of 657 cubic feet per barrel in 1980, increasing to ratios of between 15,000 to 64,000 cubic feet per barrel generally.

Conclusion

Dorchester Vanderburg No. 1--Pressure drastically reduced from expected level based on historic trend line. Decrease followed increased production by respondents. Significant volume of respondents' gas comes from the brown dolomite based on change in pressure versus production curve of Dorchester well, which

coincides with respondents' production and respondents' overlapping perforations in the brown dolomite.

Dorchester Pinnell No. 1--Eventually Almac Big Bull No. 1 will adversely affect pressure versus production trend of Dorchester well. Significant volumes of gas production from the Big Bull wells is produced from the brown dolomite. Reasons are that the producing intervals overlap those of the Dorchester Pinnel well, the brown dolomite has little structural relief in this area and the Dorchester well produces only gas from the brown dolomite, and initially when neither Big Bull well was perforated in the brown dolomite they had insignificant gas production.

Dorchester Ginn No. 1--Respondents' large gas production explains the abrupt drop in the pressure versus cumulative production curve for the Dorchester well. Respondents' eleven wells are open in the brown dolomite. Significant volumes of respondents' gas production comes from the brown dolomite.

Dorchester Mathers No. 1--Significant gas volumes being produced by the Stowers Mathers lease from the brown dolomite. Sharp drop in pressure versus production curve from Dorchester well caused by gas production from Stowers Mathers Nos. 1 and 2 and offsetting respondents' wells in Section 126 and 127 on the Sharon Lease Oil Sharon lease and the Omega Ginn lease. Initial tests for both Stowers wells showed no gas or insignificant gas when these wells completed only in granite wash.

Dorchester Kinney No. 1--Rapid drop in well pressure beginning in 1982 because of gas production from the Stowers Mackie lease and the Vanderburg Production Vanderburg lease. The Vanderburg Production Vanderburg No. 1, and the Stowers Mackie

wells until August 1983, have produced significant gas volumes. Significant amounts of this gas are being produced from the brown dolomite formation. Evidence of this is fact that drop in pressure of the Dorchester well coincides with significant production by respondents, that initially Vanderburg No. 2 produced no gas when it was perforated only in the granite wash, and increased gas production occurred at the same time as it perforated the brown dolomite.

Respondents' wells have drained gas from Dorchester's wells. Respondents' gas production is the same gas that would otherwise be produced by Dorchester. It is more than likely that the liquid produced from the Omega Energy Ginn, Zena-B Ginn, Stowers Oil Mackie and Mathers, and Vanderburg Exploration Vandy leases is oil not produced from the brown dolomite formation. The hydrocarbon analysis on the outlet liquid of gas processing units on the Dahalo Vanderburg A lease, the Vanderburg Production Vanderburg lease, the Almac Big Bull lease and the Vanderburg Exploration Sandy lease, indicates that very little, if any, of the liquid produced from such unit is oil. The small amount of liquid produced from the Sharon Lease Oil Sharon lease that may be oil almost certainly is not produced from the brown dolomite formation. No engineering explanation for the moderate gas-oil ratios fromthe Stowers Mackie and Mathers leases which do not appear to have gas processing units. Oil produced on these leases is not from the brown dolomite. Dorchester wells do not produce oil and brown dolomite formation has little structural relief. Almost all gas produced from these leases is not casinghead gas because it is not indigenous to an oil stratum and produced from that strtum with oil. Respondents' wells are draining gas from portion of the reservoir that would otherwise be drained by Dorchester wells, and it is not necessary that they do so.

(4)

89-196

NO. ________

IN THE
SUPREME COURT OF THE UNITED STATES
OCTOBER TERM, 1988

RAILROAD COMMISSION OF TEXAS,
Petitioner

V.

FEDERAL ENERGY REGULATORY COMMISSION,
Respondent

**Appendix To Petition For Writ Of Certiorari
To The United States Court Of Appeals
For The Tenth Circuit**

VOLUME 3

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EXHIBIT E

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 10-87,017

AMENDED FINAL ORDER ADOPTING AND CLARIFYING RULES AND REGULATIONS FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE AREA), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELDS, PANHANDLE, WEST FIELD AND PANHANDLE, EAST FIELD, HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS".

The Commission finds that, after statutory notice in the above-numbered docket, the presiding examiners have made and filed a proposal for decision containing findings of fact and conclusions of law, which was served on all parties of record; and that this proceeding was duly submitted to the Railroad Commission of Texas at conference held in its offices in Austin, Texas.

It has come to the Commission's attention that confusion exists among some operators in the Panhandle Fields as to the applicability of the rules presently enforced by the Commission in the administration of oil and gas conservation matters in said fields, and more particularly in the methods of

completion permitted in oil wells. So that the existing confusion can be eliminated, the Commission, after review and due consideration of a Proposal For Decision in Docket No. 10-87,017, and the exceptions and replies thereto, hereby adopts the following findings of fact and conclusions of law:

FINDINGS OF FACT

1. The proceedings in this docket were duly initiated pursuant to a notice issued January 9, 1986 by the Railroad Commission of Texas, and all affected operators received notice of the same as required by the Commission's Rules of Practice and Procedure and by the Administrative Procedure and Texas Register Act.

2. All persons seeking to become parties to this proceeding were given the opportunity to file a statement and argue on behalf of their request to be named as a party.

3. The proceedings in this docket and the hearing and record thereof are properly before the Railroad Commission of Texas.

4. A prehearing conference was held in this case on December 18, 1986, and proceedings to present evidence commenced on January 6, 1987.

5. The Railroad Commission called this hearing to review existing rules and consider adopting new or amended rules for the Panhandle Carson Field; Panhandle Collingsworth County Field; Panhandle Potter County Field; Panhandle Gray County Field; Panhandle Hutchinson County Field; Panhandle Moore County Field; Panhandle Wheeler County Field; Panhandle, West (Sanford) Field; Panhandle, West (Tubbs) Field; Panhandle (Osborne Area) Field;

Panhandle, East (Albany Dolomite, Lower) Field; Panhandle, West Field; and Panhandle, East Field in Carson, Collingsworth, Gray, Hutchinson, Moore, Wheeler, Potter, Oldham, Sherman, and Hartley Counties in Texas. These fields collectively are referred to as the Panhandle Fields.

6. The Panhandle Carson County Field; Panhandle Collingsworth County Field; Panhandle Potter County Field; Panhandle Gray County Field; Panhandle Moore County Field; Panhandle (Osborne Area) Field and Panhandle Wheeler County Field are designated by the Commission as oil fields.

The Panhandle, West (Sanford) Field; the Panhandle, West (Tubbs) Field; the Panhandle East (Albany Dolomite, Lower) Field; the Panhandle, West Field; and the Panhandle, East Field are designated by the Commission as gas fields.

7. The Panhandle Oil Field (by various county designations) has been regulated as a separate field under special rules promulgated in orders principally adopted during the 1930's and 1940's. Most of the basic special field rules are set forth in Division Two of Oil and Gas Circular 16-B (October 17, 1933), Special Order Fixing Allowable Production of Sweet and Sour Natural Gas in the Panhandle District of Texas (December 10, 1935), Order No. 20-169 (November 18, 1937), and Order No. 10-3087 (November 13, 1941). (Tr. CIG Exhibit 6, Tab 15, Tab 28, Tab 35, and Tab 53; Stumpf Exhibits 9A and 9B).

The West Panhandle Gas Field and East Panhandle Gas Field have been regulated as separate non-associated gas fields under special rules promulgated in various orders entered from the late 1940's through the early 1950's. (Tr. CIG Exhibit 6,

Tab 28, Oil and Gas Docket No. 108 [December 10, 1935]; Stumpf Exhibits 9A and 9B).

8. The discovery oil well in the Panhandle Field was the Gulf Production Company S.B. Burnett No. 2 well in Carson County. This well was drilled in 1920 and completed in 1921 with an initial pumping potential of 175 barrels per day. (Tr. 286-287; Stumpf Exhibit 4).

The discovery gas well in the Panhandle Field was the Canadian River Gas Company Masterson No. 1 well in Potter County, now known as the Colorado Interstate Gas Company Masterson C-1 well. This well was drilled in 1917 and completed in 1918 with an initial potential of 4.8 million cubic feet of gas. (Tr. 283-285; Stumpf Exhibit 3).

9. In mid-1986 there were approximately 10,796 producing oil wells and 3510 producing gas wells in the fields. Cumulative production to that point was approximately 1.245 billion barrels of oil, 6.4 trillion cubic feet of gas reported as casinghead gas and 31 trillion cubic feet of gas reported as gas well gas. (Johnson Exhibit 11, Johnson Exhibit 5, Tr. 6424, Gillespie Exhibit 10).

10. Remaining productible oil reserves total about 100 million barrels with current primary recovery technology. There is a substantial additional amount of oil in place not commercially producible under current primary recovery technology and economic conditions. (Gillespie Exhibit 5). Remaining gas well gas reserves are approximately 2.8 trillion cubic feet. (Gillespie Exhibit 10).

11. Five separately identifiable geologic rock formations may be encountered in the Panhandle

Fields: The Brown Dolomite, the Moore County Lime, the Arkosic Dolomite, the Granite Wash, and the Granite or Basement (sometimes called Fractured Granite or Weathered Granite). (Tr. 7042-7043, 2268, 4029-4030, 7957.) These formations are sometimes segregated by impermeable shale barriers, but are interconnected and pressure communicated at various points in the field. (Tr. 7964, 7829, 7385, 7389, 7442, 7494, 9076.) (Tr. 9075; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, p. 1 [December 10, 1935], Holmes Exhibit 3.)

12. The Brown Dolomite and in certain regional areas, the Moore County Lime are blanket formations containing potentially productive porosity intervals of 5% or greater extending laterally over wide distances. (Tr. 7064-7065, 7664, 7671, 7677, 7682; Bay Exhibits 72-78.) Panhandle Fields formations lying below the Brown Dolomite and, where present, the Moore County Lime, are more erratic, and porosity distribution within those lower formations tends to be local and discontinuous. (Tr. 7062, 7444-7445, 7549-7551.) In a few parts of the field; the Brown Dolomite and Moore County Lime formations are not present. (Bay Exhibit 11.)

13. Most of the oil development and production from the Panhandle Field comes from the northeastern flank of the field, where there is a heavy concentration of oil wells. There are scattered pockets of oil reserves in the remainder of the field, generally found in structural depressions and traps. (Tr. 7078-7080; Bay Exhibit 11.)

14. The upper zones of the Panhandle Fields generally produce only gas, while oil, if present at any depth, is usually found at or below 250 feet above sea level. (Tr. 8582, 8600, 8658, 9200, 3700, 7386-7388,

Gillespie Exhibits 32 and 33; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, p. 355 [November 19, 1935]; CIG Exhibit 5, Bauer, Oil and Gas Fields of the Texas Panhandle, 10 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 733, 744 [August 1926]; CIG Exhibit 5, Cotner & Crum, *Geology and Occurrence of Natural Gas in Amarillo District, Texas*, 17 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 877, 886 [August 1933]; Moore County Royalty Owners Assoc. Cross-Examination Exhibit 4; Rogatz, *Geology of Texas Panhandle Oil and Gas Field*, 23 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 983, 986 [July 1939]; Hermann Cross-Examination Exhibit 3; Hagy, *History of Development of General Geology of the Panhandle Field of Texas*. 12 PANHANDLE-PLAINS HISTORICAL REVIEW, P.7 [1939].)

15. Operators can generally use information from drillers' logs, producing characteristics of surrounding wells, selective tests of isolated intervals within the wellbore, wireline logs, core analyses, and geological samples, in addition to reference to structure and stratigraphy, in an attempt to determine the gas-oil contact in an individual oil well; but the contact cannot always be determined, and can vary substantially across the field. (Tr. 1120, 2322, 2939, 3171, 3660-3661, 4115-4116, 2939, 2218, 2324, 2460, 4021, 5046, 9104, 9106, 197, 8549-8550, 4115, 1129, 7920-7921, 3828, 2445, 2457, 4115-4116, 4130, 1182, 9091, 2322, 2622.)

16. Operators can avoid perforation of oil wells at horizons which produce only gas and can thereby maintain a low gas-oil ratio and/or low casinghead gas rate. (Tr. 5987, lines 1-8; 0008, line 21, line 6; 9070, lines 1-12; 8853; 6953, lines 9-14; Gillespie Exhibit 66; CIG Exhibit 1, Oil and Gas Docket No. 10-1322, pp. 175-176 [March 20, 1940].)

17. It is not physically necessary to perforate oil wells in upper gas-only intervals in order to recover deeper oil. (Tr. 8989-8990, 3425, 8737, 8868-8869; Gillespie Exhibit 54A.)

18. Production of gas from above oil in immediate proximity in an oil well dissipates reservoir energy thereby reducing ultimate recovery of oil and causing waste. (Tr. 8433, lines 15-20; 3695, lines 9-22; 9079, lines 11-15; 6377, line 21 - p. 6378, line 5; Strickland Exhibit 18; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, pp. 115-116 [July 18, 1935]; Oil and Gas Docket No. 108, *et al.*, p. 140 [November 19, 1935]; Gillespie Exhibit 50, *Texas Panhandle Fields: A Study of Gas Wastage and the Feasibility of Returning Waste Gas to Reservoir*, p. 19 [August 1934]; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, pp. 4-5 [December 10, 1935];, CIG Exhibit 6, Tab 75, Oil and Gas Docket No. 10-36,290 [September 16, 1957].)

19. West and East Panhandle Field gas wells generally produce from higher gas-only intervals separated in some areas by shale barriers from any oil-productive intervals at the sites of the gas wells and/or are completed at some lateral distance from any oil-bearing porosity interval, and therefore for the most part do not withdraw reservoir energy necessary for production of oil. (Tr. 8958; 6986, lines 14-19; 8426-8431; Strickland Exhibits 17 and 18.)

20. Production of unnecessary upper gas interval gas through Panhandle Field oil wells drains reserves which properly lie within the assigned proration units of West and East Panhandle gas wells. (Tr. 8775, 8778-8779, 8788, lines 14-17, 6995, lines 10-21; Gillespie Exhibits 51, 56, 58-63c.)

21. Completion of oil wells below the dry gas interval in the oil-productive portion of the Panhandle Fields reservoir(s) causes oil wells and gas wells to drain different underground pore space and minimizes competition for the same hydrocarbons on overlapping oil and gas surface proration units. (Tr. 6908, lines 3-10.)

More than 15,000 oil wells and gas wells have been drilled and are now producing under the Railroad Commission's regulatory system of assigning the same surface acreage to both oil wells and gas wells. (Tr. 2878, lines 9-18; 6908, lines 3-10.)

22. The Commission has zoned the Panhandle Field reservoir(s) into separate gas fields and oil fields. Commission field rules require that an oil well be perforated only in levels, sands, or strata productive of oil. (Commission Docket 108 Orders, December 30, 1932, and December 10, 1935, CIG Exhibit 1).

23. In 1956, all operators in the field were notified by the Commission that perforation of an oil well "in the dry gas zone" was " definitely in violation" of Railroad Commission rules. (Murray Cross-examination Exhibit 1).

24. Tex. Nat. Res. Code § 86.097 states:

> "No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive gas only."

This statute was enacted by the Legislature as a part of H.B. 266 on May 1, 1935, in specific response to abusive practices in the Panhandle Fields. (Act of May 1, 1935, ch. 120, 1935, Tex. Gen. and Spec. Laws 318; Commission Docket 108 order, December 10, 1935, CIG Exhibit 1.)

25. Gas well gas produced from the Panhandle Fields generally contains an insufficient amount of entrained liquid to justify installation of separating devices. (Tr. 6063, line 12 - 6064, line 4; 4932; Slover Cross-Examination Exhibit 1.)

26. In most instances, West Panhandle Field gas wells effectively and efficiently drain 640-acre proration units. In some instances, replacement gas wells initial potential at unexpectedly high pressures indicating inefficient drainage by the previous gas well on the same section. (Tr. 8519, line 12 - 8520, line 2; 6180, lines 9-12; 6778, lines 13-16; Gillespie Exhibits 11A-11E, 12, 13, 13A, Gillespie cross-examination exhibits 5-23.)

27. A daily casinghead gas limit for a 20 acre unit of 120 mcf per well as proposed in the hearing notice is calculated by multiplication of the statewide 2000:1 figure against the top field allowable of 60 barrels of oil per day. 95% of all oil wells in the field report daily casinghead gas capacity below 120 mcf, without benefit of lease averaging. (Tr. 8810).

27a. Oil wells drilled within the two years preceding this hearing would be entitled to produce 500 mcf of casinghead gas per day under the rules existing at the time such wells were drilled.

28. New drilling for oil between 1978 and 1985 arrested a 20 year decline curve and resulted in the additional recovery of at least 20 million barrels of oil which probably would not have been recovered otherwise. Production reported as casinghead gas approximately doubled during this interval. (Johnston Exhibits 2 and 10, Tr. 5129).

29. Some 27% of the production reported as casinghead gas in the field is coming from former LTX wells. 71.1% of all production reported as casinghead gas is being produced from some 14.4% of the oil wells in the field. (Tr. 5318, 8853).

30. Some oil well operators are maximizing gas production for economic reasons by perforating up into gas only horizons. (Tr. 1196, 3105, 3107, 3638, 3904).

31. Since the enactment of comprehensive field rules in 1935, technological advances have radically changed wellbore completion techniques and analytical methodology. (Tr. 3917-3919, CIG Exhibit 1, May 11, 1936, p. 259; Gillespie Exhibit 27, Bay Cross-examination Exhibits 6, 20 and 25, Podzemny Exhibit 1).

32. The casinghead gas production rate for new oil wells declines rapidly after initial potential, for which the 84th percentile (one standard deviation) equals 237 mcf/day. Tutt exhibit 8, Tutt rebuttal exhibit 4, Tr. 2592-2593, 3905, 5222, 5439)

33. The existing oil allocation formula which provides for a 75% well factor and 25% acreage factor is archaic and does not conform with modern Commission practice, which has moved toward acreage-oriented determination of allowables.

34. Some portions of the producing formation are lenticular or irregular such that closely spaced oil wells may encounter marked variation in initial oil potentials. (Tr. 2811-2812, 6738, 8438 lines 19-24, 8541 lines 10-13, Johnson exhibit 17)

35. Oil exploration in the traditional dry gas area of the field will be encouraged by flexibility in proration unit size requirements. (Tr. 552, 567, 759)

36. Increasing numbers of gas wells are approaching vacuum operational conditions as reservoir pressure declines. Calculated absolute open flow potentials in extremely low pressure reservoirs are not reliable and do not reflect the true productive capability of a gas well, which is more reliably verified through use of G-10 deliverability measurements. (Tr. 2167, 3861, 16 Tex. Adm. Code §3.28 and 3.31)

37. The hearing notice proposed changes in the gas well allocation formula, and no operator presented evidence in support of a formula based upon well potential.

CONCLUSIONS OF LAW

1. All action has been taken and all prerequisites fulfilled to invest the Railroad Commission with jurisdiction to decide this matter.

2. Sections 85.201, 85.202(b) and 86.081(a) of the Texas Natural Resources Code charge the Commission with the duty to regulate production of oil and gas in order to prevent waste and protect correlative rights.

3. When faced with a conflict between its mandates of preventing waste and protecting correlative rights, the Commission is required to balance all competing considerations in resolution of the matter. The prevention of waste is to be weighed heavily in this balancing process as it is the primary goal of the Commission.

Gulf Land Co. v. Atlantic Refining Co., 131 S.W.2d 73 (Tex. 1939).
Hawkins et al. v. Texas Co., 209 S.W.2d 338 (Tex. 1948)
Phillips Petroleum Company et. al. v. American Trading and Production Corporation et. al., 361 S.W.2d 942 (Tex. Civ. App. - El Paso 1962, writ ref'd n.r.e.)

Railroad Commission v. Manziel, 361 S.W.2d 560 (Tex. 1962)
Texaco, Inc. v. Railroad Commission, 583 S.W.2d 307 (Tex. 1979)
Railroad Commission of Texas v. Fain, 161 S.W.2d 498 (Tex. Civ. App - Austin 1942, writ ref'd w.o.m.)
Marrs v. Railroad Commission, 177 S.W.2d 941 (Tex. 1944)

4. Section 86.095 of the Texas Natural Resources Code authorized the Commission to zone the Panhandle Field reservoir(s) into two separate fields, to which the same tract of surface acreage may be assigned. Such dual assignment of acreage should be continued in order to prevent widespread disruption of correlative rights.

5. Section 86.097 of the Texas Natural Resources Code prohibits the completion and perforation of Panhandle oil wells at horizons which are productive only of gas.

6. Section 86.012(a)(11) of the Texas Natural Resources Code defines waste to include "the production of natural gas from a well producing oil from a stratum other than that in which the oil is found" unless produced in a separate string of casing. TEX. NAT. RES. CODE ANN. § 86.012(a)(11)(Vernon Supp. 1986).

7. "Casinghead gas" is defined at Section 86.002(10) of the Texas Natural Resources Code as "any gas or vapor indigenous to an oil stratum and produced from the stratum of oil." TEX. NAT. RES. CODE ANN. § 86.002(10)(Vernon Supp. 1987).

8. The Railroad Commission must follow and enforce the provision of the Texas Natural Resources Code. *State v. Jackson*, 376 S.W.2d 341, 344-345 (Tex.

1964); TEX. REV. CIV. STAT. ANN. art. 6252-13a §19(e)(1) (Vernon Supp. 1987).

9. Appendix 1 to the Final Order is a guideline which establishes a rebuttal presumption that a qualified well is properly completed.

10. Changes and clarifications of rules in the Panhandle Fields are appropriate in light of "changed conditions". *Railroad Commission v. Aluminum Company of America*, 380 S.W.2d 599 (Tex. 1964).

11. Adoption of the proposed order is a conservation measure that is necessary to prevent waste and to protect correlative rights in the subject fields.

Therefore, IT IS ORDERED by the Railroad Commission of Texas that the historic classification and separation of Panhandle oil and Panhandle gas fields shall be retained; and that the following fields shall be consolidated:
Panhandle East (Albany Dolomite, Lower) into Panhandle, West
Panhandle, West (Sanford) into Panhandle, West
Panhandle, West (Tubbs) into Panhandle, West (Red Cave)
Panhandle (Osborne Area) into Panhandle Wheeler County;

that various obsolete docket 108 and other orders as listed below be rescinded; and that the following rules, in addition to such of the Commission's general rules and regulations as are not in conflict herewith, be and the same are hereby clarified and adopted to govern the drilling, completion and operation of wells in the Panhandle Fields:

Oil Field Rules

Rule 1. Panhandle Field oil wells are restricted to completion in horizons bearing producible oil, production from said horizons to be capable of passing a gas-oil ratio cut-off of 100,000:1 on 72 hour test of the isolated 50 foot interval below the top of perforations if no other Appendix One oil guideline is met. No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only.

Rule 2. No oil well shall hereafter be drilled nearer than FOUR HUNDRED AND SIXTY SEVEN (467) feet to any well completed in or drilling to the same reservoir on the same lease, unitized tract, or farm; and no well shall be drilled nearer than THREE HUNDRED AND THIRTY (330) feet to any property line, lease line, or subdivision line; provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well; and the above spacing rule and the other rules to follow are for the purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned to the individual oil well for the purpose of allocating allowable oil production thereto shall be known as the prescribed proration unit. No proration unit shall consist of more than TWENTY (20) acres except as hereinafter provided, and the two farthermost points in any proration unit shall not be in excess of ONE THOUSAND FIVE HUNDRED (1500) feet removed from each other, provided, however, that is the case of long and narrow leases or in cases where because of the shape of the lease such is necessary to permit the utilization of tolerance acreage, the Commission may, after proper showing, grant exceptions to the limitations as to the shape of the proration units as herein contained. All proration units, however, shall consist of continuous and contiguous acreage which can reasonably be considered to be productive of oil.

If after the drilling of the last well on any lease and the assignment of acreage to each well thereon in accordance with the regulations of the Commission there remains an additional unassigned lease acreage of less than TWENTY (20) acres, then and in such event the remaining unassigned lease acreage up to and including a total of FIVE (5) acres may be assigned to the last well drilled on such lease, or may be distributed among any group of wells located thereon, so long as the proration units resulting from the inclusion of such additional acreage meets the limitations prescribed by the Commission.

An operator, at his option, shall be permitted to form fractional units of TEN (10) acres, with a proportional acreage allowable credit for a well on such unit, with the two farther most points of such TEN (10) acre

fractional unit not greater than ONE THOUSAND ONE HUNDRED (1100) feet removed from each other.

Upon the presentation of engineering and/or geological evidence by an operator to the Commission may approve the drilling of a second well on an existing 10 acre oil proration unit where the evidence proves that an additional well is necessary to properly drain that existing unit.

An operator at his option, shall be permitted to form units of FORTY (40) acres, with a proportional acreage allowable credit for a well on such unit, with the two farthermost points of such (40) acre unit not greater than TWO THOUSAND ONE HUNDRED (2100) feet removed from each other.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that it the acreage assigned to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled.

Rule 4. The top allowable for oil wells on a 20 acre units is set to be 60 barrels of oil per day (BOPD). The maximum daily oil allowable for each well shall be based 75% on acreage and 25% per well and will be equal to the summation of Seventy-five percent (75%) of top allowable multiplied by the ratio the number of acres assigned to the well bears to twenty (20) acres plus twenty-five percent (25%) of top allowable; thus, each well assigned twenty (20) acres will have a 60 BOPD allowable, each well assigned ten (10) acres will have a 38 BOPD allowable, and each well assigned

forty (40) acres will have a 80 BOPD allowable, with the allocation formula not being applicable to the alternate 40 acre units. In addition to the 20 acre base allowable of 60 BOPD, units between 20 and 40 acres which are not assigned tolerance acreage in accordance with Oil Rule 3 will be assigned an incremental allowable proportionate to their acreage at the rate of 1 barrel per acre per day.

Rule 5. An oil well shall be allowed to produce a daily maximum of 120 mcf of casinghead gas when assigned 20 acres, 76 mcf of casinghead gas when assigned 10 acres, and 160 mcf of casinghead gas when assigned 40 acres. Any wellbore which began commercial production within two years of the date of this order, or which is drilled and completed after the effective date of this order, or which is drilled and completed after the effective date of this order, shall be allowed to produce double such daily maximum for two years from the date of gas pipeline connection. Such additional incentive allowable shall not apply to workover of reentry of existing wellbores.

Rule 6. For W-10 testing and reporting purposes, individual oil wells shall be tested annually on a schedule beginning in April and concluding in August. Where the lease gas-oil ratio for the preceding 12 months exceeds 5000 cubic feet of gas per barrel of oil, individual well tests are required. Lease tests are permissible where the lease gas-oil ratio for the preceding 12 months is at or below 5000 cubic feet of gas per barrel of oil. Operators shall coordinate their test periods and procedures with the District 10 office.

In the event a lease test shows gas-oil ratio between 5,000 cubic feet of gas per barrel of oil and 30,000 cubic feet of gas per barrel of oil, and each well on such lease has been tested within the previous three calendar years and qualifies as an oil well, then such individual

well tests shall not be required annually if the lease wide gas-oil ratio has not increased from the year in which individual well tests were performed. In the event new wells have been added during such three year period, and initial tests on such new well shows a GOR below 30,000:1, individual annual well tests shall not be required.

Gas Field Rules

Rule 1. The division and boundary line between the Panhandle, East and Panhandle, West gas fields as set forth in docket 10-23,955 is retained; the West field being bounded on the east by a line traversed by the following set out course; to wit:

"Beginning at a point in Gray County, Texas, represented by the southeast corner of Section 9, Block 3, I&GN Survey; thence south along the east lines of Sections 10 and 11 in the same Block and Survey to a point represented by the southeast corner of Section 11; thence west along the south line of said Section 11 to a point represented by the southeast corner of Section 14 in the same block and survey; thence south along the east line of Section 13 in the same block and survey; thence west to the northeast corner of Section 30, located in Block B-2, H&GN survey; thence south along the east lines of Sections 30, 29, 28, and 27, located in said Block B-2 H&GN Survey, to a point represented by the southeast corner of said Section 27; thence east along the south line of Section 4, Block B-2 H&GN Survey, to the southeast corner of said Section 4, thence south along the east lines of Sections 5, 6, 7, 8, 9, and 10 located in said Block B-2 H&GN Survey, to a point represented by the southeast corner of said Section 10; thence east along the north line of Section 12, Block B-2 H&GN Survey to the northeast corner of said Section 12; thence south along the east lines of said Section 12 to the southeast corner of said Section

12, continuing south along the west lines of Section 2 and 1 of the C&M Survey to a point represented by the southwest corner of said Section 1, C&N Survey; thence east along the south line of said Section 1, C&N Survey, continuing east along the south line of Section 3 of the J.J. Purdick survey to the southeast corner of said Section 3; thence south along the west line of Section 5, Block 2, of the H&GN Survey to the southwest corner of said Section 5; thence east along the south line of said Section 5 and Section 4 of the same block and survey to the southeast corner of said Section 4; thence north to a point represented by the southwest corner of Section 2 of the same block and survey; thence east along the south lines of said Section 2, and Sections 20, 19, 18, 17, 16, 15, and 14 of Block 30, H&GN Survey, and Sections 118, 119, and 120 of Block 23, H&GN Survey to a point represented by the southeast corner of said Section 120; thence south along the east lines of Sections 115, 94, 89, 68, 63, 42, and 37, Block 23, H&GN Survey, to the extremities of production; the sections, blocks, and surveys herein referred to all being located in Gray County, Texas.

Rule 2. No gas well in the Panhandle, West field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line or subdivision line; No gas well in the Panhandle, East field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line, or subdivision line;

Provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of

property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well' and the above spacing rule and the other rules to follow are for the purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned an individual non-associated gas well for the purpose of allocating allowable gas production thereto shall be known as a gas proration unit, and such acreage may be claimed for each non-associated gas reservoir independently of any other reservoir. No gas proration unit shall contain less than SIX HUNDRED FORTY (640) acres in the Panhandle, West field, or ONE HUNDRED SIXTY (160) acres in the Panhandle, East field except as hereinafter provided; and no such acreage shall be included in any proration unit formed or created subsequent to the effective date of this order and allocated to the well thereon unless the farthermost two points on the unit created by the inclusion of such acreage be not greater than EIGHT THOUSAND FIVE HUNDRED (8500) feet in the Panhandle, West field and FOUR THOUSAND FIVE HUNDRED (4500) in the Panhandle, East field; provided that tolerance

acreage of ten percent (10%) shall be allowed for each unit so that an amount not to exceed a maximum of SEVEN HUNDRED FOUR (704) acres in the Panhandle, West field and ONE HUNDRED SEVENTY SIX (176) acres in the Panhandle, East field may be assigned, and each unit containing less than SIX HUNDRED FORTY (640) acres in the Panhandle, West field or ONE HUNDRED SIXTY (160) in the Panhandle, East field shall be a fractional proration unit.

Upon the presentation of engineering and/or geological evidence by an operator to the Commission under the provision of Statewide Rule 38, the Commission may approve the drilling of a second gas well on an existing 640 acre gas proration unit where the evidence proves that an additional well is necessary to efficiently and effectively drain that existing unit.

All such proration units shall consist of continuous and contiguous acreage which can reasonably be considered to be productive of gas.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that it the acreage assigned to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been pooled.

Rule 4. The daily allowable production of gas from individual gas wells completed in the Panhandle, West and East gas fields, shall be determined by allocating the allowable production, after deductions have been made for wells which are incapable of

producing their gas allowables, among the individual wells in the following manner:

Two-thirds (2/3) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the product of the acreage assigned such well for allowable purposes and the rock pressure of such well bears to the summation of this product for all other proratable gas wells producing from the respective field (2/3 acreage times rock pressure).

One third (1/3) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the current deliverability of such well bears to the summation of the current deliverabilities for all proratable wells producing from the respective field (1/3 current deliverability).

For purposes of this rule, "rock pressure" means shut-in wellhead pressure reported in pounds per square inch absolute (psia) on the most recent gas well status report (Form G-10, as amended, or its successor) for the well.

Rule 5. Separating devices are not required for gas wells completed in dry gas (gas only) horizons. On-lease separating devices (prior to metering) are required where gas wells are completed in depths productive of oil, or in any case where on-lease separating devices would recover over 12 barrels per year of condensate or hydrocarbon liquid. On-lease drip collectors or interceptors are permissible separating devices if all products separated are accurately reported in compliance with Statewide Rules 54 and 85 when removed from the lease. All condensate or hydrocarbon liquid production over 1 barrel per gas well per month recovered on the lease must be reported on the monthly production report.

Rule 6. Gas wells in the Panhandle, West field shall be tested in May, June, July and August of each year, with reports due September first. Gas well test data shall be filed using form G-1 and G-10 rather than forms GWT-10, GWT10-A, GWT-11 and GWT-11A.

No test is required of gas wells in the Panhandle, East Field due to extremely low reservoir pressure.

General Rules

Because it is not always possible to determine the gas-oil contact in an individual wellbore, and a contact when present can vary substantially in subsea elevation across the field, the Commission determines that regulation of the field is best implemented without reference to an absolute gas-oil contact level, but rather by a set of guidelines which are attached as Appendix One to this order.

Existing and future oil wells meeting one of the oil well criteria set forth in Appendix One will be presumed to have been properly completed. Operators shall have a period of one year to bring existing wells into compliance with an Appendix One guideline in order to receive the presumption.

All operators electing to complete a new oil well or add perforation to an existing well such that no Appendix One oil well guideline is met must make such note on their W-2 filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of oil, and shall indicate that the District Office and all other oil and gas operators on the same and offsetting sections were notified prior to testing and indicate whether or not testing was witnessed by the District Office or another operator, and the identity of each such witness.

Existing gas wells will be presumed to have been properly completed if they meet one of the gas well completion criteria set forth in Appendix One to the Final Order in this docket. Operators shall have a period of one year to bring existing wells into compliance with an Appendix One guideline in order to receive the presumption.

All operators electing to complete a new gas well or deepen an existing well such that no Appendix One gas well guideline is met must make such note on their G-1 filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of dry gas or gas only, and shall indicate that the District Office and all other oil and gas operators on the same and offsetting sections were notified prior to testing and indicate whether or not testing was witnessed by the District Office or another operator, and the identity of each such witness.

Operators shall notify all other Panhandle Field oil and gas operators on the same and offsetting sections at least five days in advance of any test relied upon for compliance with field rules or Appendix One guidelines and shall permit these operators to witness such tests and have copies of any measurements, data, and analysis associated with the tests.

These requirements and guidelines are based on a Commission finding that there is segregation of oil and gas in the Panhandle fields such that the two are generally divided and separated into lower oil intervals and upper gas intervals. For this reason, dual assignment of the same surface acreage to both the oil and the gas fields for recovery from two properly completed and classified wells, one for recovery of oil and the other for recovery of gas, shall be permitted to

continue as it has since the inception of comprehensive field rules in 1935.

An operator with well(s) which fail to meet any of the completion guidelines may file an application for hearing that an exception to the field rules is necessary to prevent waste or protect correlative rights. In connection with any such application, notice must be given to all overlapping and offsetting operators, unleased mineral interests, and other affected entities. If such application is unprotested the Director of Oil and Gas shall be authorized to grant an exception based upon submitted evidence that such exception will in fact prevent waste or protect correlative rights. Such application shall be subject to full discovery by the Commission and other parties.

Once a oil or gas well has been completed in compliance with Appendix 1 guidelines, the presumption of proper completion will continue unless the well is recompleted with perforations at different elevations.

The special rules and directives set forth in Oil and Gas Docket 10-77,314 (LTX product reports and classification) and the related staff memorandum September 24, 1985 are retained. The order authorizing the West Pampa Repressurization program (docket 10-8333) is retained. The Staff Memorandum of December 17, 1973 (District 10 - Lease-wide Testing) is rescinded. All other prior fieldwide rules, directives and memoranda are hereby superceded and rescinded, including but not limited to the following:

Date	Docket No.	Purpose
08/27/30	112	Establishing Field Rules
11/01/30	112	Amending 8/37/30 Order
01/23/31	112	Establishing Field Rules
04/04/31	113	Establishing Field Rules
10/13/31	108	Time limits on drilling
10/30/31	108	Establishing Field Rules
10/30/31	108	Common Purchaser Law
10/30/31	122,119	Rules governing common purchasers
05/09/32	108	25% Open Flow Limit
06/15/32	None	Oil and Gas Circular 15
11/18/32	108	Granting Exemptions
12/06/32	108	Establishing Field Rules
12/30/32	108	Determining Allowable Production
12/30/32	108	Establishing Field Rules
10/17/33	None	Adopting Circular 16-B
05/12/34	108	Amending Rule 2
05/15/34	None	Readopting Circular 16-B
05/24/35	108	Reducing Potentials
07/20/35	108	Fixing Allowable Gas Production
08/01/35	108	Fixing Allowable Gas Production
08/05/35	108	Fixing Allowable Gas Production
08/06/35	108	Changing Method of Taking Potentials
08/28/35	108	Fixing Allowable Gas Production
09/25/35	108	Fixing Allowable Gas Production
10/17/35	108	Fixing Allowable Gas Production
10/23/35	108	Regarding Pending Court Proceedings
11/22/35	108	Changing Method of Taking Potentials
12/10/35	108	Fixing Allowable Gas Production
01/14/36	108	Authorizing Gas-Oil Ratio Survey
02/03/36	108	Amending Above
04/27/36	108	Revoking Authorization of Survey
09/15/36	108	Authorizing Gas-Oil Ratio Survey
02/25/37	108	Setting a Gas-Oil Ratio
10/02/37	10-93	Limiting Gas Volumes
11/18/37	20-169	Fixing Allowable Gas Production
05/04/38	10-316	Fixing Allowable Gas Production
05/25/38	10-338	Amending Above
10/15/38	10-453	Setting Out Rules
11/25/38	10-499	Limiting Gas Volumes
01/14/39	10-548	Amending Above

Date (cont.)	Docket No. (cont.)	Purpose (cont.)
01/18/39	20-550	Classifying Condensate Wells
01/31/39	10-564	Fixing Allowable Gas Production
04/01/39	10-621	Supplementing Above
01/11/40	10-1222	Amending Circular 16-B
03/12/40	10-1384	Promulgating Spacing Rule
03/25/40	10-4449	Fixing Allowable Gas Production
03/28/40	10-1445	Amending Circular 16-B
04/30/40	10-1543	Suspending Above
07/08/40	10-1685	Repressurization of Oil Sands
08/23/40	10-1832	Amending Circular 16-B
11/20/40	10-2080	Fixing Classification Method
08/29/41	10-2898	Amending Circular 16-B
11/13/41	10-3087	Limiting Gas Volumes
04/06/42	10-3593	Limiting Gas Production
10/29/42	10-4135	Limiting Gas Production
05/19/43	10-4833	Limiting Gas Production
08/14/44	10-6600	Amending Spacing Rules
05/24/48	10-12,465	Requiring Well Tests
09/24/48	10-13,196	Sweet and Sour Gas
01/10/49	10-13,783	Amending Above
02/06/50	10-17,595	Amending Above
12/19/51	10-22,479	Roughness Friction Factor
03/04/52	10-23,060	Determination of Absolute Potentials
06/09/52	10-23,807	Amending Order No. 10-13,196
06/30/52	10-23,955	Rescinding Order No. 10-23,807 (Except retaining the boundary line between the East and the West Gas fields as set forth in this order.)
07/21/52	10-24,144	Amending Order No. 10-23,060
09/18/52	10-24,493	Gas Measurement Rules
05/19/54	10-29,542	Gas Well Testing Rules
05/19/54	10-29,544	Gas Well Testing Rules
08/30/54	10-30,121	Amending Rule 3(c)
11/07/55	10-32,363	Revising East Field Rules
09/16/57	10-36,290	Requiring Gas-Oil Ratio Surveys
11/22/60	10-44,633	East Field Operating Rules
10/11/77	10-67,681	GOR Test Procedures

IT IS FURTHER ORDERED THAT each exception to the examiners' proposal for decision not expressly granted herein is hereby overruled. All requested findings of fact and conclusions of law which are not expressly adopted herein are denied. All pending motions not previously granted or granted herein are hereby denied.

Signed this 20th day of March, 1989. This order shall be effective from and after May 1, 1989.

RAILROAD COMMISSION OF TEXAS

/s/ John Sharp,
Commissioner

/s/ Jim Nugent,
Commissioner

Attest

Secretary

Appendix 1 Guidelines for Compliance

Oil Wells

Because the gas-oil contact varies and is not clearly defined in all parts of the field, and because remedial work on old wellbores is sometimes ineffective, fraught with risk of damage to the well, and for economic reasons may cause premature abandonment of a well producing crude oil, the following guidelines are offered as "fingerprints" indicating presumed compliance with field rules which prohibit perforation of oil wells in dry gas horizons.

Commission staff engineers will assume a Panhandle oil well is properly completed if it tests and produces at a gas-oil ratio of less than 100,000:1 (statutory requirement) and it meets any one of the following criteria and there is no evidence of inaccurate reporting of perforations or formation tops and bottoms and there is no evidence of inaccurate reporting of oil or gas production or test volumes. This will be a rebuttable presumption, but the complainant shall bear the burden of proof.

1. The top of perforations is at or below +250 feet (sea level datum).

> (Gillespie Exhibit 32; 95% of all cable tool drillers' log first oil shows are at or below +250).

2. The most recent 12 month average producing GOR does not exceed 5000:1.

> (85.6% of all oil wells in the field pass this test. Passing leases have an average lease GOR of 2742:1; Gillespie exhibit 66, Tr. 8816, 9070)

(In July of 1935, 92.6% of all oil produced in the field came from wells having a GOR at or below 20,000:1, Hearing of July 18, 1935, p. 72, CIG Exhibit 1)
(For the 12 month period preceding August, 1986, the affected leases produced 17% of the oil and 71% of the reported casinghead gas in the field. (Tr. 8820).

3. A test of the isolated 50 foot interval below the top of perforations yields enough oil on stabilized 72 hour test to classify as a statutory oil well, notice of such test to be provided at least five days in advance to the RRC District 10 office and to all oil and gas operators on the same and offsetting sections. Such test may be witnessed by any person with an affected interest. It is intended this test be required only to assist the operator in qualifying the wells under these guidelines, and shall not be required thereafter unless directed by the Commission.

(Where there are both producible oil and free gas horizons, there may be a transition zone of up to 50 feet between the two. Tr. 7729, 7422, 8416, 8440).

4. The well is located in a structurally anomalous area of high oil, this category to be limited to the following structural features, and:

a.Top of perforations is at or below +350 (sea level datum).

1. Rockwall County School Land Low - Gray County
- R.C.S.L. Survey Sections 1-15
- C.C.S.D.R.G.N.G. R.R. Survey Sections 1-10
(Bay exhibits 16 and 80)

2. Deep Lake Graben - Gray County
- H.&.G.N. R.R. Survey Block B-2
Sections 79, 80, 100-102, 110, 111, 129, 130, 141-143, 157, 160, 171-174, 187-189, and 202-204
(Bay exhibits 16, 24 and 80, Reynolds exhibit 21)

3. LeFors Graben Margin - Gray County
- H.&.G.N. R.R. Survey Block B-2
Sections 7, 8, 24, 25, 36, 37, 55, 56, 65, 66, 85-87, 94, 95.
116 and 117
(Bay exhibits 15, 16 and 29)

4. White Deer Graben - Carson County
- I.&G.N. R.R. Survey Block 4
Sections 50, 51, 52, 58, 59 and 60
(Bay exhibits 15, 16, 22, 34 and 35)

5. Deahl Low - Carson County
- A.B.&M. Survey Block 3
Sections 4, 5, 6, 7 and 8
- B.S.&F. Survey
Sections 2 and 4 (N. and E. of Deal Community)
(Bay exhibits 15 and 16)

6. Mother Goose Grabin - Moore County
- G.&M. Survey Block 2
Sections 5, 6, 7 and 8
(Bay exhibits 16, 62 and 64)

b. Top of perforation is at or below +450 (sea level datum).

1. Carson County Basin East Margin - Carson County

-I.&.G.N. R.R. Survey Block 7
Sections 43-46, 62-66, 69-71, 84 and 85
(Bay exhibits 15, 16, 22, 28 and 80, Reynolds exhibits 6 and 7, Stumpf exhibit 18)

2. Carson County Basin North Margin - Carson County - I.&.G.N. R.R. Survey Block 7
Sections 10-16, 28 and 29
(Bay exhibits 15, 16 and 33)

3. Bell Low - Gray County
- H.&G.N. R.R. Survey Block 2
Sections 124, 147, 153, 154, 177-179, 183-185, 206-208 and 214 (Bay exhibits 15, 16 and 80)

5. The top of perforations is lower than the base of perforations in any producing gas well(s) located within a one mile radius of the subject well.

(July 8, 1985 Commission Memorandum to all operators in the fields, page 2, paragraph 3.)

6. The well has produced not more than 20,000 cubic feet of gas per day (24) hours) during the most recent Railroad Commission test (either W-2 test or W-10 test) and the most recent 12-month average production is not more than 20,000 cubic feet of gas per day.

(Tr. 5987, 8807, Gillespie Exhibit 2 page 3)

Gas Wells

In order to provide parity and equity with the presumptions afforded oil well completions under these

guidelines, the following are proposed as "fingerprints" indicating presumed compliance with field rules which prohibit perforation of gas wells in horizons productive of oil.

Commission staff engineers will assume a Panhandle gas well is properly completed if it tests and produces at a gas-oil ratio of more than 100,000:1 (statutory requirement) and it meets any one of the following criteria and there is no evidence of inaccurate reporting of perforations or formation tops and bottoms and there is no evidence of inaccurate reporting of oil or gas production or tested volumes. This will be a rebuttable presumption, but the complainant shall bear the burden of proof.

1. The bottom of perforations is at or above +50 feet (sea level datum), except in the Oil Well Guidelines Section Four areas where proper completion is presumed if above +350 feet (sea level datum) in area 4(a) or +450 feet (sea level datum) in area 4(b).

(Gillespie exhibit 33; 95% of lowest known gas shows on cable tool driller's logs occur above +50 feet).

2. The most recent 12 month average production of liquid hydrocarbons of any kind does not exceed one *barrel per month.

(Johnston exhibit 5; Tr. 5140, 5147).

3. A test of the isolated 50 foot interval above the bottom of perforations produces at a gas-oil ratio of over 100,000 cubic feet of gas per barrel of oil on a stabilized 72 hour test, notice of such test to be provided

at least 5 days in advance to the RRC District 10 Office and to all oil or gas operators on the same and offsetting sections, such test may be witnessed by any person with an affected interest. It is intended this test be required only to assist the operator in qualifying the wells under these guidelines, and shall not be required thereafter unless directed by the Commission.

4. The producing interval of the well is not overlapped by the perforations of a producing oil well within a one mile radius of the subject well.
(July 8, 1985 Commission memorandum to all operators in the fields, p. 2, paragraph 3.)

EXHIBIT F

§81.051. Jurisdiction of Commission

(a) The commission has jurisdiction over all:

(1) common carrier pipelines defined in Section 111.002 of this code in Texas;

(2) oil and gas wells in Texas;

(3) persons owning or operating pipelines in Texas; and

(4) persons owning or engaged in drilling or operating oil or gas wells in Texas.

(b) Persons listed in Subsection (a) of this section and their pipelines and oil and gas wells are subject to the jurisdiction conferred by law on the commission.

§81.052. Rules

The commission may adopt all necessary rules for governing and regulating persons and their operations under the jurisdiction of the commission as set forth in Section 81.051, including such rules as the commission may consider necessary and appropriate to implement state responsibility under any federal law or rules governing such persons and their operations.

§81.053. Commission Powers

In the discharge of its duties and the enforcement of its jurisdiction under this title, the ccmmission shall:

(1) institute suits;

(2) hear and determine complaints;

(3) require the attendance of witnesses and pay their expenses out of funds provided for that purpose;

(4) obtain the issuance of writs and process which may be necessary for the enforcement of its orders; and

(5) punish for contempt or disobedience of its orders in the manner provided for the district courts.

§85.041. Acts Prohibited in Violation of Laws, Rules, and Orders

(a) The purchase, acquisition, or sale, or the transporting, refining, processing, or handling in any other way, of oil or gas, produced in whole or in part in violation of any oil or gas conservation statute of this state or of any rule or order of the commission under such a statute, is prohibited.

(b) The purchase, acquisition, or sale, or the transporting, refining, processing, or handling in any other way, of any product of oil or gas which is derived in whole or in part from oil or gas or any product of either, which was in whole or in part from oil or gas or any product of either, which was in whole or part produced, purchased, acquired, sold, transported, refined, processed, or handled in any other way, in violation of any oil or gas conservation statute of this state, or of any rule or order of the commission under such a statute, is prohibited.

§85.042. Rules and Orders

(a) The commission may promulgate and enforce rules and orders necessary to carry into effect the provisions of Section 85.041 of this code and to prevent that section's violation.

(b) When necessary, the commission shall make and enforce rules either general in their nature or applicable to particular fields for the prevention of actual waste of oil or operations in the field dangerous to life or property.

§85.043. Application of Certain Rules and Orders

If the commission requires a showing that refined products were manufactured from oil legally produced, the requirement shall be of uniform application throughout the state; provided that, if the rule or order is promulgated for the purpose of controlling a condition in any local area or preventing a violation in any local area, then on the complaint of a person that the same or similar conditions exist in some other local area and the promulgation and enforcement of the rule could be beneficially applied to that additional area, the commission shall determine whether or not those conditions do exist, and if it is shown that they do, the rule or order shall be enlarged to include the additional area.

§85.044. Exempt Purchases

The provisions of Sections 85.041 through 85.043 of this code do not apply to the purchase of products of oil if made by the ultimate consumer from a retail distributor of the products.

§85.045. Waste Illegal and Prohibited

The production, storage, or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited.

§85.046. Waste

(a) The term "waste," among other things, specifically includes:

(1) operation of any oil well or wells with an inefficient gas-oil ratio and the commission may determine and prescribe by order the permitted gas-oil ratio for the operation of oil wells;

(2) drowning with water a stratum or part of a stratum that is capable of producing oil or gas or both in paying quantities;

(3) underground waste or loss, however caused and whether or not the cause of the underground waste or loss is defined in this section;

(4) permitted any natural gas well to burn wastefully;

(5) creation of unnecessary fire hazards;

(6) physical waste or loss incident to or resulting from drilling, equipping, locating, spacing, or operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas from any pool;

(7) waste or loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool; however, it is not the intent of this section or the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd

Legislature, 1st Called Session, 1931, as amended, to require repressuring of an oil pool or to require that the separately owned properties in any pool be unitized under one management, control, or ownership;

(8) surface waste or surface loss, including the temporary or permanent storage of oil or the placing of any product of oil in open pits or earthen storage, and other forms of surface waste or surface loss including unnecessary or excessive surface losses, or destruction without beneficial use, either of oil or gas;

(9) escape of gas into the open air in excess of the amount necessary in the efficient drilling or operating of the well from a well producing both oil and gas;

(10) production of oil in excess of transportation or market facilities or reasonable market demand, and the commission may determine when excess production exists or is imminent and ascertain the reasonable market demand; and

(11) surface or subsurface waste of hydrocarbons, including the physical or economic waste or loss of hydrocarbons in the creation, operation, maintenance, or abandonment of an underground hydrocarbon storage facility.

(b) Notwithstanding the provisions contained in this section or elsewhere in this code or in other statutes or laws, the commission may permit production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas where the commission, after notice and

hearing, has found that producing oil or gas or oil and gas in a commingled state will prevent waste, promote conservation, or protect correlative rights.

§85.047. Exclusion From Definition of Waste

The use of gas produced from an oil well within the permitted gas-oil ratio for manufacture of natural gasoline shall not be included in the definition of waste.

§85.048. Authority to Limit Production

(a) Under the provisions of Subsection (10), Section 85.046 of this code, the commission shall not restrict the production of oil from any new field brought into production by exploration until the total production from that field is 10,000 barrels of oil a day in the aggregate.

(b) The commission's authority to restrict production from a new field under other provisions of Section 86.046 of this code is not limited by this section.

§85.049. Hearing

(a) On verified complaint of any person interested in the subject matter than waste of oil or gas is taking place in this state or is reasonably imminent, or on its own initiative, the commission, after proper

notice, may hold a hearing to determine whether or not waste is taking place or is reasonably imminent and if any rule or order should be adopted or if any other actions should be taken to correct, prevent, or lessen the waste.

(b) The hearing shall be held at the time and place determined by the commission.

§85.050. Procedure of Hearings

(a) At the hearing, parties shall be entitled to be heard and to introduce evidence and require the attendance of witnesses.

(b) The production of evidence may be required as provided by law.

§85.051. Adoption of Rule or Order

If the commission finds at the hearing that waste is taking place or is reasonably imminent, it shall adopt a rule or order in the manner provided by law as it considers reasonably required to correct, prevent, or lessen the waste.

§85.052. Compliance With Rule or Order

From and after the promulgation of a rule or order of the commission, it is the duty of each person affected by the rule or order to comply with it.

§85.053. Distribution, Proration, and Apportionment of Allowable Production

(a) If a rule or order of the commission limits or fixes in a pool or portion of a pool the production of oil, or the production of gas from wells producing gas only, the commission shall distribute, prorate, or otherwise apportion or allocate the allowable production among the various producers on a reasonable basis.

(b) When, as provided in Subsection (b) of Section 85.046 or Subsection (b) of Section 86.012 of this code, as amended, the commission has permitted production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas, the commission may distribute, prorate, apportion, or allocate the production of such commingled separate multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas as if they were a single pool; provided, however, that:

(i) the commingling and distribution, proration, apportionment, or allocation of separate accumulations with commission established discovery dates after January 1, 1940, and prior to June 1, 1945, shall not serve to expand, add to, or extend the vertical or areal extent of any single pool;

(ii) such commingling shall not cause the allocation of allowable production from a well producing from any separate accumulation or accumulations to be less than that which would result from the commission applying the provisions of Section 86.095 of this code to such accumulation or accumulations;

(iii) the allocation of the allowable for such commingled production shall be based on not less than two factors which the Railroad Commission shall take into account as directed by Section 86.089 of this code; and

(iv) No gas well in any field falling within the classification under Subdivision (i) above where commingled separate accumulations of gas are being prorated under the authority granted by this Subsection (b) shall be assigned an allowable in excess of its production during the most recent production period reported to the commission and in the absence of any reported production the assigned allowable shall not exceed the open-flow potential of such well as reported to the commission; provided, however, that the commission may, if it finds special conditions require such, make a greater assignment.

§85.054. Allowable Production of Oil

(a) To prevent unreasonable discrimination in favor of one pool as against another, and on written complaint and proof of such discrimination, the commission may allocate or apportion the allowable production of oil on a fair and reasonable basis among the various pools in the state.

(b) In allocating or ascertaining the reasonable market demand for the entire state, the reasonable market demand of one pool shall not be discriminated against in favor of another pool.

(c) The commission shall determine the reasonable market of the respective pool as the basis for determining the allotments to be assigned to the respective pool so that discrimination may be prevented.

§85.055. Allowable Production of Gas

(a) If full production from wells producing gas only from a common source of supply of gas in this state is in excess of the reasonable market demand, the commission shall inquire into the production and reasonable market demand for the gas and shall determine the allowable production from the common source of supply.

(b) The allowable production from a common source of supply is that portion of the reasonable market demand that can be produced without waste.

(c) The commission shall allocate, distribute, or apportion the allowable production from the common source of supply among the various producers on a reasonable basis and shall limit the production of each producer to the amount allocated or apportioned to the producer.

(d) When, as provided in Subsection (b) of Section 85.046 or Subsection (b) of Section 86.012 of this code, as amended, the commission has permitted production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas, the commission may allocate, distribute, or apportion the production of such commingled separate multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas as if they were a single common source of supply; provided, however, that:

(i) The commingling and distribution, proration, apportionment, or allocation of separate accumulations with commission established discovery dates after January 1, 1940, and prior to June 1, 1945, shall not serve to expand, add to, or extend the vertical or areal extent of any single common source of supply;

(ii) such commingling shall not cause the allocation of allowable production from a well producing from any separate accumulation or accumulations to be less than that which would result from the commission, applying the provisions of Section 86.095 to such accumulation or accumulations;

(iii) the allocation of the allowable for such commingled production shall be based on not less than two such factors which the Railroad Commission shall take into account as directed by Section 86.089 of this code; and

no gas well in any field falling within the classification under (i) above where commingled separate accumulations of gas are being prorated under the authority granted by this Subsection (d) shall be assigned an allowable in excess of its production during the most recent production period reported to the commission and in the absence of any reported production the assigned allowable shall not exceed the open-flow potential of such well as reported to the commission; provided, however, that the commission may, if it finds special conditions require such, make a greater assignment.

§85.201. Adoption of Rules and Orders

The commission shall make and enforce rules and orders for the conservation of oil and gas and prevention of waste of oil and gas.

§85.202. Purposes of Rules and Orders

(a) The rules and orders of the commission shall include rules and orders:

(1) to prevent waste, as defined in Section 85.046 of this code, of oil and gas in drilling and producing operations and in the storage, piping, and distribution of oil and gas;

(2) to require dry or abandoned wells to be plugged in a manner that will confine oil, gas, and water in the strata in which they are found and prevent them from escaping into other strata;

(3) for the drilling of wells and preserving a record of the drilling of wells;

(4) to require wells to be drilled and operated in a manner that will prevent injury to adjoining property;

(5) to prevent oil and gas and water from escaping from the strata in which they are found into other strata;

(6) to provide rules for shooting wells and for separating oil from gas;

(7) to require records to be kept and reports made; and

(8) to provide for issuance of permits, tenders, and other evidences of permission when the issuance of the permits, tenders, or permission is necessary or incident to the enforcement of the commission's rules or orders for the prevention of waste.

(b) The commission shall do all things necessary for the conservation of oil and gas and prevention of waste of oil and gas and may adopt other rules and orders as may be necessary for those purposes.

§85.241. Suits by Interested Persons

Any interested person who is affected by the conservation laws of this state or orders of the commission relating to oil or gas and the waste of oil or gas, and who is dissatisfied with any of these laws or orders, may file suit against the commission or its members in a court of competent jurisdiction in Travis County to test the validity of the law or order.

§86.002. Definitions

In this chapter:

(1) "Oil" means crude petroleum oil.

(2) "Gas" means natural gas.

(3) "Commission" means the Railroad Commission of Texas.

(4) "Common reservoir" means all or part of any oil or gas field or oil and gas field that comprises and includes any area that is underlaid or that, from geological or other scientific data or experiments or from drilling operations or other evidence, appears to be underlaid by a common pool or accumulation of oil or gas or oil and gas.

(5) "Gas well" means a well that:

(A) produces gas not associated or blended with oil at the time of production;

(B) produces more than 100,000 cubic feet of gas to each barrel of oil from the same producing horizon; or

(C) produces gas from a formation or producing horizon productive of gas only encountered in a well bore through which oil also is produced through the inside of another string of casing.

(6) "Oil well" means any well that produces one barrel or more of oil to each 100,000 cubic feet of gas.

(7) "Dry gas" means gas produced from a stratum that does not produce oil.

(8) "Sour gas" means gas:

(A) containing more than one and one-half grains of hydrogen sulphide per 100 cubic feet;

(B) containing more than 30 grains of total sulphur per 100 cubic feet; or

(C) whith in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

(9) "Sweet gas" means all gas except sour gas and casinghead gas.

(10) "Casinghead gas" means any gas or vapor indigenous to an oil stratum and produced from the stratum with oil.

(11) "Natural gasoline" means gasoline manufactured from casinghead gas or from any gas.

(12) "Cubic foot of gas" or "standard cubic foot of gas" means the volume of gas, including natural and casinghead gas, contained in one cubic foot of space at a standard pressure base of 14.65 pounds per square inch absolute and at a standard temperature base of 60 degrees Fahrenheit, and if the conditions of pressure and temperature differ from this standard, conversion of the volume from the differing conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

§86.011. Prohibition Against Waste

The production, transportation, or use of gas in a manner, in an amount, or under conditions which constitute waste is unlawful and is prohibited.

§86.012. Definition of Waste

(a) The term "waste" includes:

(1) the operation of an oil well or wells with an inefficient gas-oil ratio;

(2) the drowning with water of a stratum or part of a stratum capable of producing gas in paying quantities;

(3) permitting a gas well to burn wastefully;

(4) the creation of unnecessary fire hazards;

(5) physical waste or loss incident to or resulting from so drilling, equipping, or operating a well or wells as to reduce or tend to reduce the ultimate recovery of gas from any pool;

(6) the escape of gas from a well producing both oil and gas into the open air in excess of the amount that is necessary in the efficient drilling or operation of the well;

(7) the production of gas in excess of transportation or market facilities or reasonable market demand for the type of gas produced;

(8) the use of gas for the manufacture of carbon black without first having extracted the natural gasoline content from the gas, except it shall not be necessary to first extract the natural gasoline content from the gas where it is utilized in a plant producing an average recovery of not less than five pounds of carbon black to each 1,000 cubic feet of gas;

(9) the use of sweet gas produced from a gas well for the manufacture of carbon black unless it is used in a plant producing an average recovery of not less than five pounds of black to each 1,000 cubic feet and unless the sweet gas is produced from a well located in a common reservoir producing both sweet and sour gas;

(10) permitting gas produced from a gas well to escape into the air before or after the gas has been processed for its gasoline content, unless authorized as provided in Section 86.185 of this code;

(11) the production of natural gas from a well producing oil from a stratum other than that in which the oil is found unless the gas is produced in a separate string of casing from that in which the oil is produced;

(12) the production of more than 100,000 cubic feet of gas to each barrel of crude petroleum oil unless the gas is put to one or more of the uses authorized for the type of gas so produced under allocations made by the commission or unless authorized as provided in Section 86.185 of this code; and

(13) underground waste or loss however caused and whether or not defined in other subdivisions of this section.

(b) Notwithstanding the provisions contained in this section or elsewhere in this code or in other statutes or laws, the commission may permit production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas where the commission, after notice and hearing, has found that producing oil or gas or oil and gas in a commingled state will prevent waste, promote conservation, or protect correlative rights.

§86.041. In General

The commission has broad discretion in administering the provisions of this chapter and may adopt any rule or order in the manner provided by law that it finds necessary to effectuate the provisions and purposes of this chapter.

§86.042. Rules and Orders

The commission shall adopt and enforce rules and orders to:

(1) conserve and prevent the waste of gas;

(2) prevent the waste of gas in drilling and producing operations and in the piping and distribution of gas;

(3) require dry or abandoned wells to be plugged in a way that confines gas and water in the strata in which they are found and prevents them from escaping into other strata;

(4) provide for drilling wells and preserving a record of them;

(5) require wells to be drilled and operated in a manner that prevents injury to adjoining property;

(6) prevent gas and water from escaping from the strata in which they are found into other strata;

(7) require records to be kept and reports made;

(8) provide for the issuance of permits and other evidences of permission when the issuance of the permit or permission is necessary or incident to the enforcement of its blanket grant of authority to make any rules necessary to effectuate the law; and

(9) otherwise accomplish the purposes of this chapter.

§86.081. Regulation of Production

(a) For the protection of public and private interests, the commission shall prorate and regulate the daily gas well production from each common reservoir to:

(1) prevent waste; and

(2) adjust the correlative rights and opportunities of each owner of gas in a common reservoir to produce and use or sell the gas as permitted in this chapter.

(b) When, as provided in Subsection (b) of Section 85.046 or Subsection (b) of Section 86.012 of this code, as amended, the commission has permitted production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas, the commission may prorate, allocate, and regulate the production of gas or oil and gas, the commission may prorate, allocate, and regulate the production of such commingled, separate multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas as if they were a single common reservoir; provided, however, that:

(i) the commingling and distribution, proration, apportionment, or allocation of separate accumulations with commission established discovery dates after January 1, 1940, and prior to June 1, 1945, shall not serve to expand, add to, or extend the vertical or areal extent of any single common reservoir;

(ii) such commingling shall not cause the allocation of allowable production from a well producing from any separate accumulation or accumulations to be less than that which would result from the commission applying the provisions of Section 86.095 of this code to such accumulation or accumulations;

(iii) the allocation of the allowable for such cummingled production shall be based on not less than two factors which the Railroad Commission shall take into account as directed by Section 86.089 of this code; and

no gas well in any field falling within the classification under Subdivision (i) above where commingled separate accumulations of gas are being prorated under the authority granted by this Subsection (b) shall be assigned an allowable in excess of its production during the most recent production period reported to the commission and in the absence of any reported production the assigned allowable shall not exceed the open-flow potential of such well as reported to the commission; provided, however, that the commission may, if it finds special conditions require such, make a greater assignment.

§86.082. Exercise of Authority to Prevent Waste

The commission shall exercise its authority to prevent waste when the presence or imminence of waste is supported by a finding based on the evidence introduced at a hearing after proper notice.

§86.083. Exercise of Authority to Adjust Correlative Rights and Opportunities

The commission shall exercise its authority to adjust correlative rights and opportunities of each owner of gas in a common reservoir to produce and use or sell the gas when evidence introduced at a hearing after proper notice will support a finding made by the commission that the aggregate lawful volume of the open flow or daily potential capacity to produce of all gas wells located in a common reservoir is in excess of the daily reasonable market demand for gas from gas wells that may be produced from the common reservoir, to be used as permitted in this chapter.

§86.084. Determination of Status of Production

(a) The commission shall determine the status of gas production from all reservoirs in the state.

(b) If the commission finds that waste exists or is imminent in the production of gas from a reservoir, or that the capacity of the wells to produce gas from a reservoir exceeds the market demand for gas from the reservoir, the commission by proper order shall prorate and regulate the gas production from the reservoir on a reasonable basis.

§86.093. Effect of Oil and Gas Stratum on Gas Only Stratum

If gas is produced from one stratum and oil and gas are produced from another stratum in the same well bore, the commission shall take into account the amount of gas produced from the oil stratum in determining the amount of gas that may be produced from the stratum producing gas only. The commission may subtract the amount of the casinghead gas produced from the dry gas that would be allocated to the well if it produced dry gas and may restrict the dry gas production accordingly.

§86.094. Authority to Increase Take Above Allowable

If unforeseen contingencies increase the demand for gas required by a distributor, transporter, or purchaser to an amount in excess of the total allowable production of the wells to which he is connected, the distributor, transporter, or purchaser may increase his take ratably from all these wells in order to supply his demand for gas, provided that notice of the increase and the amount of the increase are given to the commission within five days; and provided further, the commission, at its next hearing, shall adjust the inequality of withdraws caused by the increase in fixing the allowable production of the various wells in the common reservoir or zones.

§86.095. Zoning Common Reservoirs

(a) The commission shall zone a common reservoir if, on consideration of the evidence introduced at a hearing, it finds that either the prevention of waste or adjustment of correlative rights and opportunities, or both, as designated in Section 86.081 of this code, may be accomplished more adequately by zoning the common reservoir.

(b) If the commission zones a common reservoir, each zone shall be regarded as a separate common reservoir in making allocations of daily allowable production as provided in this chapter.

(c) If the commission zones a common reservoir, the commission:

(1) shall allocate to each zone its just proportion of the market demand for gas from the common reservoir;

(2) shall establish appropriate rules applicable to each zone;

(3) may adjust its orders to the practicable conditions that exist; and

(4) may enter any reasonable order necessary to effectuate the purposes of this chapter.

(d) The commission may segregate a sour gas area from a sweet gas area and is not required to restrict the allowable production of the sour gas zone to the same percentages that may be produced from the sweet gas zone.

§86.096. Failure to Use or Sell Allowable Production

If the commission finds that the owner of a gas well failed or refused to use or sell the allowable production from his well when the owner was offered a connection or market for the gas at a reasonable price, the well shall be excluded from consideration in allocating the daily allowable production from the reservoir or zone in which it is located until the owner of the well signifies to the commission his desire to use or sell the gas. In all other cases, all gas wells shall be taken into account in allocating the allowable production among wells producing the same type of gas.

§86.097. Production of Gas From Oil Well

No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only.

EXHIBIT G

§3.10. Restriction of Production of Oil and Gas from Different Strata

(a) General prohibition. Oil or gas shall not be produced from different strata through the same string of casing except as provided in this section.

(b) Exception.

(1) After notice and hearing, the commission may grant an exception to subsection (a) of this section to permit production from a well or wells commingling oil or gas or oil and gas from two separate reservoirs or multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas if commingled production will:

(A) prevent waste;

(B) promote conservation rights; or

(C) protect correlative rights.

(2) Subsequent exceptions for wells producing from the same reservoirs may be granted administratively without further notice and hearing.

(c) Commingled production. Commingled production of gas pursuant to subsection (b) of this section shall be considered production from a common source of supply for purposes of proration and allocation.

§3.13. Casing, Cementing, Drilling, and Completion Requirements

(a) General.

(1) The operator is responsible for compliance with this section during all operations at the well. It is the intent of all provisions of this section that casing be securely anchored in the hole in order to effectively control the well at all times, all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm, and all potentially productive zones be isolated and sealed off to prevent vertical migration of fluids or gases behind the casing. When the section does not detail specific methods to achieve these objectives, the responsible party shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology.

(2) Definitions. The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise:

(A) Stand under pressure - To leave the hydrostatic column pressure in the well acting as the natural force without adding any external pump pressure. The provisions are complied with if a float collar is used and found to be holding at the completion of the cement job.

(B) Zone of critical cement - For surface casing strings shall be the bottom 20% of the casing string, but shall be no

more than 1,000 feet nor less than 300 feet. The zone of critical cement extends to the land surface for surface casing strings of 300 feet of less.

(C) Protection depth - Depth to which usable-quality water must be protected, as determined by the Texas Department of Water Resources, which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain usable-quality water.

(D) Productive horizon - Any stratum known to contain oil, gas, or geothermal resource in commercial quantities in the area.

(b) Onshore and inland waters.

(1) General.

(A) All casing cemented in any well shall be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which the pipe will be subjected in the well. For new pipe, the mill test pressure may be used to fulfill this requirement. As an alternative to hydrostatic testing, a full length electromagnetic, ultrasonic, radiation thickness gauging, or magnetic particle inspection may be employed.

(B) Wellhead assemblies shall be used on wells to maintain surface control

of the well. Each component of the wellhead shall have a pressure rating equal to or greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, or producing the well.

(C) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed as soon as surface casing is set. This equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by the commission or its duly accredited agent.

(D) When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing string by 0.2. The maximum test pressure required, however, unless otherwise ordered by the commission, need not exceed 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 10% or more from the original test pressure, the casing shall be condemned until the leak is corrected. A pressure test demonstrating less than a 10% pressure drop after 30 minutes is proof that the condition has been corrected.

(2) Surface casing.

(A) Amount required.

(i) An operator shall set and cement sufficient surface casing to protect all usable quality water strata, as defined by the Texas Department of Water Resources. Before drilling any well in any field or area in which no field rules are in effect or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from the Texas Department of Water Resources stating the protection depth. In no case, however, is surface casing to be set deeper than 200 feet below the specified depth without prior approval from the commission.

(ii) Any well drilled to a total depth of 1,000 feet or less below the ground surface may be drilled without setting surface casing provided no shallow gas sands or abnormally high pressures are known to exist at depths shallower than 1,000 feet below the ground surface; and further, provided that production casing is cemented from the shoe to the ground surface by the pump and plug method.

(B) Cementing. Cementing shall be by the pump and plug method. Sufficient

cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement does not circulate to ground surface or the bottom of the cellar, the operator or his representative shall obtain the approval of the district director for the procedures to be used to perform additional cementing operations, if needed, to cement surface casing from the top of the cement to the ground surface.

(C) Cement quality.

(i) Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

(ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed.

(iii) In addition to the minimum compressive strength of

the cement, the API free water separation shall average no more than six milliters per 250 milliliters of cement tested in accordance with the current API RP 10B.

(vi) The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

(D) Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following

temperatures and at atmospheric pressure:

(i) for the cement in the zone of critical cement, the test temperature shall be within 10°F of the formation equilibrium temperature at the top of the zone of critical cement.

(ii) for the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60°F, whichever is greater.

(E) Cementing report. Upon completion of the well, a cementing report must be filed with the commission furnishing complete data concerning the cementing of surface casing in the well as specified on a form furnished by the commission. The operator of the well or his duly authorized agent having personal knowledge of the facts, and representatives or the cementing company performing the cementing job, must sign the form attesting to compliance with the cementing requirements of the commission.

(F) Centralizers. Surface casing shall be centralized at the shoe, above and below a stage collar or diverting tool, if run, and through usable-quality water zones. In nondeviated holes, pipe centralization as follows is required: a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to

the bottom of the cellar. All centralizers shall meet API spec 10D specifications. In deviated holes, the operator shall provide additional centralization.

(G) Alternative surface casing programs.

(i) An alternative method of fresh water protection may be approved upon written application to the appropriate district director. The operator shall state the reason (economics, well control, etc.) for the alternative fresh water protection method and outline the alternate program for casing and cementing through the protection depth for strata containing usable-quality water. Alternative programs for setting more than specified amounts of surface casing for well control purposes may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. The district director may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by the director of field operations. If the proposal is not approved administratively, the operator may request a public hearing. An operator may request a public hearing. An operator shall obtain approval by any

alternative program before commencing operations.

(ii) Any alternative casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside this string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

(iii) Any alternative casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey or cement bond log. The appropriate district office shall be notified prior to running the required temperature survey or bond log. After the top of cement outside the casing is determined, the operator or his representative shall contact the appropriate district director and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon com-

pletion of the well, a cementing report shall be filed with the commission on the prescribed form.

(iv) Before parallel (nonconcentric) strings of pipe are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

(3) Intermediate casing.

(A) Cementing method. Each intermediate string of casing shall be cemented from the shoe to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 feet above the top of the shallowest productive horizon or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.

(B) Alternate method. In the event the distance from the casing shoe to the top of the shallowest productive horizon make cementing, as specified above, impossible or impractical, the multi-stage process may be used to cement the casing in a manner that will effectively seal off all such possible productive horizons and prevent fluid migration to or from such strata within the wellbore.

(4) Production casing.

(A) Cementing method. The producing string of casing shall be cemented by the pump and plug method, or another method approved by the commission, with sufficient cement to fill the annular space back of the casing to the surface or to a point at least 600 feet above the shoe. If any productive horizon is open to the wellbore above the casing shoe, the casing shall be cemented in a manner that effectively seals off all such possibly productive horizons by one of the methods specified for intermediate casing in paragraph (b)(3) of this section.

(B) Isolation of associated gas zones. The position of the gas-oil contact shall be determined by coring, electric log, or testing. The producing string shall be landed and cemented below the gas-oil contact, or set completely through and perforated in the oil-saturated portion of the reservoir below the gas-oil contact.

(5) Tubing and storm choke requirements.

(A) Tubing requirements for oil wells. All flowing oil wells shall be equipped with and produced through tubing. When tubing is run inside casing in any flowing oil well, the bottom of the tubing shall be at a point not higher than 100 feet above the top of the producing interval nor more than 50 feet above the top of a line, if one is used. In a multiple zone structure, however, when an operator elects to equip a well in such a manner

that small through-the-tubing type tools may be used to perforate, complete, plug back, or recomplete without the necessity of removing the installed tubing, the bottom of the tubing may be set at a distance up to, but not exceeding 1,000 feet above the top of the perforated or open-hole interval actually open for production into the wellbore. In no case shall tubing be set at a depth of less than 70% of the distance from the surface of the ground to the top of the interval actually open to production.

(B) Storm Choke. All flowing oil, gas, and geothermal resource wells located in bays, estuaries, lakes, rivers, or streams must be equipped with a storm choke or similar safety device installed in the tubing a minimum of 100 feet below the mud line.

(c) Texas offshore casing, cementing, drilling, and completion requirements.

(1) Casing. The casing program shall include at least three strings of pipe, in addition to such drive pipe as the operator may desire, which shall be set in accordance with the following program:

(A) Conductor casing. A string of new pipe, or reconditioned pipe with substantially the same characteristics as new pipe, shall be set and cemented at a depth of not less than 300 feet TVD (true vertical depth) nor more than 800 feet TVD below the mud line. Sufficient cement shall be sued to fill the annular

space back of the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations.

(B) Surface casing. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi) or reconditioned pipe that has been tested to an equal pressure. Sufficient cement shall be used to fill the annular space behind the pipe to the mud line; however, cement may be washed out or displaced to a maximum depth of 50 feet below the mud line to facilitate pipe removal on abandonment. Surface casing shall be set and cemented in all cases prior to penetration of known shallow oil and gas formations, or upon encountering such formations. In all cases, surface casing shall be set prior to drilling below 3,500 feet TVD. Minimum depths for surface casing are as follows:

(i) Surface Casing Depth Table.

Proposed Total Vertical Depth of Well	*Surface*
to 7000 feet	25% of proposed total depth of well

7000-10,000 feet	2000 feet
10,000 and below	2500 feet

(ii) Casing test. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling plug or initiating tests. Casing shall be tested by pump pressure to at least 1,000 psi. If, at the end of 30 minutes, the pressure shows a drop of 100 psi or more, the casing shall be condemned until the leak is corrected. A pressure test demonstrating a drop of less than 100 psi after 30 minutes is proof that the condition has been corrected.

(C) Production casing or oil string. The production casing or oil string shall be new or reconditioned pile with a mill test of at least 2,000 psi that has been tested to an equal pressure and after cementing shall be tested by pump pressure to at least 1,500 psi. If, at the end of 30 minutes, the pressure shows a drop of 150 psi or more, the casing shall be condemned. After corrective operations, the casing shall again be tested in the same manner. Cementing shall be by the pump and plug method. Sufficient cement shall be used to fill the calculated annular space above the shoe to protect any prospective producing horizons and to a depth that isolates abnormal pressure from normal pressure (0.465 gradient). A float collar or other means to stop the cement plug shall be inserted in the

casing string above the shoe. Cement shall be allowed to stand under pressure for a minimum of eight hours before drilling the plug or initiating tests.

(2) Blowout preventers.

(A) Before drilling below the conductor casing, the operator shall install at least one remotely controlled blowout preventer with a mechanism for automatically diverting the drilling fluid to the mud system when the blowout preventer is activated.

(B) After setting and cementing the surface casing, a minimum of two remotely controlled hydraulic ram-type blowout preventers (one equipped with blind rams and one with pipe rams), valves, and manifolds for circulating drilling fluid shall be installed for the purpose of controlling the well at all times. The ram-type blowout preventers, valves, and manifolds shall be tested to 100% of rated working pressure, and the annular-type blowout preventer shall be tested to 1,000 psi at the time of installation. During drilling and completion operations, the ram-type blowout preventers shall be tested by closing at least once each trip, and the annular-type preventer shall be tested by closing on drill pipe once each week.

(3) Kelly cock. During drilling, the well shall be fitted with an upper kelly cock in proper working order to close in the drill string below

hose and swivel, when necessary for well control. A lower kelly safety valve shall be installed so that it can be run through the blowout preventer. When needed for well control, the operator shall maintain at all times on the rig floor safety valves to include:

(A) full-opening valve of similar design as the lower kelly safety valves; and

(B) inside blowout preventer valve with wrenches, handling tools, and necessary subs for all drilling pipe sizes in use.

(4) Mud program. The characteristics, use, and testing of drilling mud and conduct of related drilling procedures shall be designed to prevent the blowout of any well. Adequate supplies of mud of sufficient weight and other acceptable characteristics shall be maintained. Mud tests shall be made frequently. Adequate mud testing equipment shall be kept on the drilling platform at all times. The hole shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to fill the hole each time shall be measured to assure that it corresponds with the displacement of pipe pulled. A derrick floor recording mud pit level indicator shall be installed and operative at all times. A careful watch for swabbing action shall be maintained when pulling out of hole. Mudgas separation equipment shall be installed and operated.

(5) Casinghead.

(A) Requirement. All wells shall be equipped with casingheads of sufficient rated working pressure, with adequate connections and valves available, to permit pumping mud-laden fluid between any two strings of casing at the surface.

(B) Casinghead test procedure. Any well showing sustained pressures on the casinghead, or leaking gas or oil between the surface casing and the oil string, shall be tested in the following manner: The well shall be killed with water or mud and pump pressure applied. Should the pressure gauge on the casinghead reflect the applied pressure, the casing shall be condemned. After corrective measures have been taken, the casing shall be tested in the same manner. This method shall be used when the origin of the pressure cannot be determined otherwise.

(6) Christmas tree. All completed wells shall be equipped with Christmas tree fittings and wellhead connections with a rated working pressure equal to, or greater than, the surface shut-in pressure of the well. The tubing shall be equipped with a master valves, but two master valves shall be used on all wells with surface pressures in excess of 5,000 psi. All wellhead connections shall be assembled and tested prior to installation by a fluid pressure equal to the test pressure of the fitting employed.

(7) Storm choke and safety valve. A storm choke or similar safety device shall be installed in the tubing of all completed flowing wells to a minimum of 100 feet below the mud line. Such

wells shall have the tubing-casing annulus sealed below the mud line. A safety valve shall be installed at the wellhead downstream of the wing valve. All oil, gas, and geothermal resource gathering lines shall have check valves at their connections to the wellhead.

(8) Pipeline shut-off valve. All gathering pipelines designed to transport oil, gas, condensate, or other oil or geothermal resource field fluids from a well or platform shall be equipped with automatically controlled shut-off valves at critical points in the pipeline system. Other safety equipment must be in full working order as a safeguard against spillage from pipeline ruptures.

(9) Training. Effective January 1, 1981, all tool pushers, drilling superintendents, and operators' representatives (when the operator is in control of the drilling) shall be required to furnish certification of satisfactory completion of a USGS-approved school on well control equipment and techniques. The certification shall be renewed every two years by attending a USGS-approved refresher course. These training requirements apply to all drilling operations on lands which underlie fresh or marine waters in Texas.

§3.39. Proration and Drilling Units--Contiguity of Acreage and Exception Thereto

(a) Proration and drilling units established for individual wells drilled or to be drilled shall consist of acreage which is contiguous.

(b) An exception to the contiguous acreage provision may be granted at the operator's request if acreage that is to be included in the proration or drilling unit is separated by a long, narrow right-of-way tract.

§3.40. Assignment of Acreage to Pooled Development and Proration Units

(a) Acreage up to the amount specified in applicable field rules may be pooled into a development or proration unit, provided that an operator must file with the commission a certified plat delineating the pooled unit, and a certificate of pooling authority wherein it is stated that the tracts are pooled by authority of an agreement between the various interest holders in the several tracts committed to the unit, with such tracts separately identified and the gross number of acres in each of said tracts shown separately, with a total gross acreage allowed not to exceed the unit size authorized by rule.

(b) If a tract to be pooled has an outstanding interest for which pooling authority does not exist, the tract may be assigned to a unit where authority exists in the remaining undivided interest, provided, that total gross acreage in the tract is included for allocation purposes, and the certificate filed with the commission shows that a certain undivided interest is outstanding in the tract. The commission will not allow an operator to assign only his undivided interest out of a basic tract, where a nonpooled interest exists.

(c) The nonpooled undivided interest holder retains his development rights in his basic tract, and

should such rights be exercised, authority to develop the basic tract be approved by the commission, and a well completed as a producer thereon, then the entire interest in the basic tract must be allocated to said well, and any interest insofar as it is pooled with another tract for allocation purposes. Splitting of undivided interest in a basic tract, between two or more wells on two or more tracts is not acceptable.

(d) Acreage assigned to a well for drilling and development, or for allocation of allowable, shall not be assigned to any other well or wells projected to or completed in the same reservoir; such duplicate assignment of acreage is not acceptable, provided, however, that this limitation shall not prevent the reformation of development or proration units so long as no duplicate assignment of acreage occurs, and further, that such reformation does not violate other conservation regulations.

§3.69. Definitions

The following words and terms, when used in this chapter, shall have the following meanings, unless the context clearly indicates otherwise:

Adjacent estuarine zones--This term embraces the area inland from the coast line of Texas and is comprised of the bays, inlets, and estuaries along the gulf coast.

By-product--Any element found in a geothermal formation which when brought to the surface is not used in geothermal heat or pressure inducting energy generation.

Casinghead gas--Any gas or vapor, or both, indigenous to an oil stratum and produced from such stratum with oil.

Commission--The Railroad Commission of Texas.

Common reservoir--Any oil, gas, or geothermal resources field or part thereof which comprises and includes any area which is underlaid, or which from geological or other scientific data or experiments or from drilling operations or other evidence appears to be underlaid by a common pool or accumulation of oil, gas, or geothermal resources.

Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60°F. Whenever the conditions of pressure and temperature differ from the standard in this definition, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation,

District office--The commission-designated office for the geographic area in which the property or act subject to regulation is located or arises.

Dry gas--Any natural gas produced from a stratum that does not produce crude petroleum oil.

Exploratory well--Any well drilled to a depth greater than the existing fresh water strata, as determined by the Texas Department of Water Resources, for the purpose of securing geological or other information which may be obtained by

penetrating the earth with a drill bit, coring equipment, and similar tools, and includes what is commonly referred to in the industry as "slim hole tests" or "core hole tests" and the like.

Gas lift--Gas lift by the use of gas not in solution with oil produced.

Gas well--Any well:

(A) which produces natural gas not associated or blended with crude petroleum oil at the time of production;

(B) which produces more than 100,000 cubic feet of natural gas to each barrel of crude petroleum oil from the same producing horizon; or

(C) which produces natural gas from formation or producing horizon productive of gas only encountered in a well bore through which crude petroleum oil also is produced through the inside of another string of casing or tubing. A well which produces hydrocarbon liquids, a part of which is formed by a condensation from a gas phase and a part of which is crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil, shall be classified as a gas well unless there is produced one barrel or more of crude petroleum oil per 100,000 cubic feet of natural gas; and that the term "crude petroleum oil" shall not be construed to mean any liquid hydrocarbon mixture or portion thereof which is not in the liquid phase in the reservoir, removed from the reservoir in such liquid phase, and obtained at the surface as such.

Gatherer--Includes any pipeline, truck, motor vehicle, boat, barge, or person authorized to gather or accept oil, gas, or geothermal resources from lease production or lease storage.

Geothermal energy and associated resources--

(A) All products of geothermal processes, embracing indigenous steam, hot water and hot brines, and geopressured water.

(B) Steam and other gases, hot water and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations.

(C) Heat or other associated energy found in geothermal formations.

(D) Any by-product derived from them.

Geothermal resource well--A well drilled within the established limits of a designated geothermal field.

(A) A geopressured geothermal well must be completed within a geopressured aquifer.

(B) A geopressured aquifer is a water-bearing zone with a pressure gradient in excess of 0.5 pounds per square inch per foot and a temperature gradient in excess of 1.6°F. per 100 foot of depth.

Marginal well--Any oil well which is incapable of producing its maximum capacity of oil except by pumping, gas lift, or other means of artificial lift, and which well so equipped is capable, under normal

unrestricted operating conditions, of producing such daily quantities of oil as herein set out, as would be damaged, or result in a loss of production ultimately recoverable, or cause the premature abandonment of same, if its maximum daily production were artificially curtailed. The following described wells shall be deemed "marginal wells" in this state:

(A) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 10 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a depth of 2,000 feet or less.

(B) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 20 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 2,000 feet and less in depth than 4,000 feet.

(C) Any oil wells incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum capacity of 25 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing from a horizon deeper than 4,000 feet and less in depth than 6,000 feet.

(D) Any oil well incapable of producing its maximum daily capacity of oil except by

pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 30 barrels or less, averaged over the preceding 30 consecutive days, producing from a horizon deeper than 6,000 feet and less in depth than 8,000 feet.

(E) Any oil well incapable of producing its maximum daily capacity of oil except by pumping, gas lift, or other means of artificial lift, within this state and having a maximum daily capacity for production of 35 barrels or less, averaged over the preceding 10 consecutive days of stabilized production, producing, from a horizon deeper than 8,000 feet. (Reference Order No. 20-59,200, Effective 5-1-69).

Natural gas or gas--These terms shall have the same meaning, as used in the rules, regulations, or forms of the commission.

Natural gasoline--Gasoline manufactured from casinghead gas or from any natural gas.

Oil well--Any well which produces one barrel or more crude petroleum oil to each 100,000 cubic feet of natural gas.

Operator--A person, acting for himself or as an agent for others and designated to the commission as the one who has the primary responsibility for complying with its rules and regulations in any and all acts subject to the jurisdiction of the commission.

Person--Any natural person, corporation, association, partnership, receiver, trustee, guardian, executor, administrator, and a fiduciary or representative of any kind.

Product--Includes refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, casinghead gasoline, natural gas gasoline, gas oil, naphtha, distillate, gasoline, kerosene, benzine, wash oil, waste oil, blended gasoline, lubricating oil, blends or mixtures of petroleum and/or any and all liquid products or byproducts derived from crude petroleum oil or gas, whether hereinabove enumerated or not.

Sour gas--Any natural gas containing more than 1-1/2 grains of hydrogen sulphide per 100 cubic feet or more than 30 grains of total sulphur per 100 cubic feet, or gas which in its natural state is found by the commission to be unfit for use in generating light or fuel for domestic purposes.

Sweet gas--All natural gas except sour gas and casinghead gas.

Texas offshore--This term embraces the area in the Gulf of Mexico seaward of the coast line of Texas comprised of:

(A) the three league area confirmed to the State of Texas by the Submerged Land Act (43 United States Code section 1301-1315); and

(B) the area seaward of such three league area owned by the United States.

Transportation or to transport--The movement of any crude petroleum oil or products of crude petroleum oil or the products of either from any receptacle in which any such crude petroleum or products of crude petroleum oil or the products of either has been stored

to any other receptacle by any means or method whatsoever, including the movement by any pipeline, railway, truck, motor vehicle, barge, boat, or railway tank car. It is the purpose of this definition to include the movement or transportation of crude petroleum oil and products of crude petroleum oil and the products of either by any means whatsoever from any receptacle containing the same to any other receptacle anywhere within or from the State of Texas, regardless of whether or not possession or control or ownership change.

Transporter or transporting agency--Includes any common carrier by pipeline, railway, truck, motor vehicle, boat, or barge, and/or any person transporting oil or a product by pipeline, railway, truck, motor vehicle, boat, or barge.

(5) (2)

Nos. 89-196 and 89-394

In the Supreme Court of the United States

October Term, 1989

Railroad Commission of Texas, petitioner

v.

Federal Energy Regulatory Commission

Walker Operating Corporation, et al., petitioners

v.

Federal Energy Regulatory Commission

ON PETITIONS FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE TENTH CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

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QUESTION PRESENTED

Whether the court of appeals properly upheld the decision of the Federal Energy Regulatory Commission that certain oil well operators had diverted natural gas dedicated to interstate commerce, in violation of Section 7(b) of the Natural Gas Act, 15 U.S.C. 717f(b), and sold that gas at a price in excess of the lawful maximum price, in violation of Section 504(a)(1) of the Natural Gas Policy Act of 1978, 15 U.S.C. 3414(a)(1).

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OCTOBER TERM, 1989

No. 89-196

RAILROAD COMMISSION OF TEXAS, PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION

No. 89-394

WALKER OPERATING CORPORATION, ET AL., PETITIONERS

v.

FEDERAL ENERGY REGULATORY COMMISSION

ON PETITIONS FOR A WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE TENTH CIRCUIT

BRIEF FOR THE FEDERAL ENERGY REGULATORY COMMISSION IN OPPOSITION

OPINIONS BELOW

The opinion of the court of appeals (Pet. App. A1-A41)[1] is reported at 874 F.2d 1320. The order of the Federal Energy Regulatory Commission (Pet. App. B1-B17) is reported at 32 F.E.R.C. ¶ 61,043. The order of the Federal Energy Regulatory Commission on rehearing (Pet. App. C1-C36) is reported at 33 F.E.R.C. ¶ 61,207.

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[1] "Pet. App." refers to the appendix to the petition in No. 89-196.

JURISDICTION

The judgment of the court of appeals was entered on April 28, 1989. The petitions for a writ of certiorari were each filed on July 27, 1989. The jurisdiction of this Court is invoked under 28 U.S.C. 1254(1).

STATEMENT

This case involves challenges to an order issued by the Federal Energy Regulatory Commission determining that certain oil well operators had diverted natural gas dedicated to interstate commerce, in violation of Section 7(b) of the Natural Gas Act (NGA), 15 U.S.C. 717f(b), and sold that gas at a price in excess of the lawful maximum price, in violation of Section 504(a)(1) of the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. 3414(a)(1).

1. a. The Natural Gas Act, 15 U.S.C. 717 *et seq.*, reflects a segmented scheme of regulation, consisting of production and gathering at one end, interstate transportation and sale in interstate commerce for resale in the middle, and local distribution at the other end. See 15 U.S.C. 717(b). The NGA gives the Commission comprehensive regulatory authority over the "middle segment, with production on one end and distribution on the other committed to the control of different states." *FPC* v. *East Ohio Gas Co.*, 338 U.S. 464, 488 (1950) (Jackson, J., dissenting).

Within the "middle segment," the Commission regulates the natural gas market through its authority under Section 7(e) of the NGA, 15 U.S.C. 717f(e), to issue certificates of public convenience and necessity authorizing natural gas producers to transport or sell gas in interstate commerce. Under Section 7(b) of the NGA, 15 U.S.C. 717f(b), the Commission's issuance of a certificate "commits" or "dedi-

cates" gas covered by the certificate to the interstate market, such that the certificate holder must continue to supply gas to that market unless the Commission grants permission to abandon certificated service. See, *e.g.*, *United Gas Pipe Line Co.* v. *McCombs*, 442 U.S. 529, 536 (1979). In addition, under Sections 4 and 5 of the NGA (15 U.S.C. 717c and 717d) the Commission regulates the price and other terms of sales for resale and of transportation, ensuring that the rates and charges for such services, as well as all rules, regulations, practices, and contracts affecting those rates and charges, are just and reasonable (see 15 U.S.C. 717c(a)). See also *Northwest Central Pipeline Corp.* v. *State Corporation Comm'n*, 109 S. Ct. 1262, 1271-1272 (1989).

b. In 1978 Congress adopted the Natural Gas Policy Act of 1978, 15 U.S.C. 3301 *et seq.*, "to give market forces a more significant role in determining the supply, the demand, and the price of natural gas." *Transcontinental Gas Pipe Line Corp.* v. *State Oil & Gas Bd.*, 474 U.S. 409, 422 (1986). The NGPA set new, higher price ceilings for "new" or hard-to-produce gas as an incentive to production, and eliminated, over time, FERC's jurisdiction over the wellhead price of that "new" gas. See Section 103 of the NGPA, 15 U.S.C. 3313.[2] However, "old" gas, *i.e.*, gas already "committed or dedicated to interstate commerce" when the NGPA was enacted and not otherwise excluded from federal regulation under Section 601(a)(1)(B) of the NGPA, 15 U.S.C. 3431(a)(1)(B), remains subject to the price ceilings established under the NGA, as well as the abandonment requirements of Section 7. See Section 104 of the NGPA, 15 U.S.C. 3314.

[2] "New" gas covered by the higher ceiling prices (and not subject to the dedication and abandonment requirements of the NGA) includes gas produced from new onshore wells drilled after February 19, 1977. See Section 103(c) of the NGPA, 15 U.S.C. 3313(c).

The NGPA specifically prohibits the sale of natural gas "at a first sale price in excess of any applicable maximum lawful price." Section 504(a)(1) of the NGPA, 15 U.S.C. 3414(a)(1). In conjunction with the price control scheme, the NGPA denominates state regulatory agencies as "jurisdictional agencies," and charges them with the responsibility to determine the category for which a well qualifies under the NGPA. See Section 503 of the NGPA, 15 U.S.C. 3413. An applicant submits information to the jurisdictional agency, and the jurisdictional agency then transmits notice of its determination to FERC for review and approval.[3]

2. a. This case arises from the West Panhandle Field, which covers a vast hydrocarbon reservoir in the Texas Panhandle. This reservoir contains both oil-producing and gas-producing formations. Pet. App. A5.[4] Petitioner Railroad Commission of Texas (RCT) regulates oil and gas production in the West Panhandle Field. State well-spacing rules allow one oil well on every 10 acres (a 10-acre proration unit), but one gas well only on every 640 acres (a 640-acre proration unit). Given the formations in the West Panhandle Field, oil well operators must frequently drill through gas-bearing rock to reach the lower-lying oil deposits. Texas state law therefore distinguishes between the

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[3] In order to reject a jurisdictional agency's determination, FERC must make a preliminary finding that no substantial evidence supports that determination within 45 days of receiving notice, and must further make a final determination within 120 days of that finding. If FERC does not take the requisite actions within the 165-day period, the jurisdictional agency's determination becomes final. See Section 503(b)(1) of the NGPA, 15 U.S.C. 3413(b)(1).

[4] As a result, the same surface area may contain both oil and gas wells with separate parties owning the gas and oil production rights. Pet. App. D7.

production of gas from oil, as opposed to gas production from gas proration units. *Id.* at A6-A7.

Texas state law permits an oil operator to keep any "casinghead gas" he produces as a necessary byproduct of producing oil, *i.e.*, "any gas or vapor indigenous to an oil stratum and produced from the stratum with oil." Tex. Nat. Res. Code Ann. § 86.002(10) (Vernon 1978); see Pet. App. F17. The RCT, however, regulates drilling activity to ensure that oil well operators do not take "dry gas," *i.e.*, gas produced from gas-bearing rock, because such gas belongs to gas proration unit owners. Tex. Nat. Res. Code Ann. §§ 86.002(7), 86.097 (Vernon 1978); see Pet. App. F16, F27. In order to enforce this regulatory scheme, the RCT, since 1933, has required all Texas oil well operators to establish the line of contact between their oil wells and gas-bearing rock formations (known as the "gas-oil contact"), and to perforate their oil wells only *below* the gas-oil contact. *Id.* at D8 (citing Texas Statewide Rule 13(b)(4)).

b. In 1983, FERC's enforcement staff launched a preliminary investigation of natural gas sales by certain oil operators in the West Panhandle Field. As a result, in February 1984, the Commission issued an order initiating a show cause proceeding. The order identified 37 oil well operators in the West Panhandle Field, 35 of whom are petitioners in this case (see note 6, *infra*), whose 196 oil wells were located below the same surface acreage as 35 gas wells from which Dorchester Gas Producing Company sold natural gas for resale in interstate commerce. Pet. App. A8.

Dorchester sold its gas under the terms of a certificate of convenience and necessity that FERC had issued in 1954 under Section 7(b) of the NGA, 15 U.S.C. 717f(b). As a result, most of Dorchester's gas qualified as "old" gas for purposes of the pricing provisions of Section 104 of the

NGPA, 15 U.S.C. 3314.[5] In May 1984, Dorchester's gas sales price under Section 104 was 46 or 47 cents per thousand (MM) Btu. Pet. App. D9-D11. On the other hand, almost all of petitioners' oil wells were completed after November 9, 1978, the effective date for the NGPA. *Id.* at D12. As a result, under Section 503 of the NGPA, 15 U.S.C. 3413, the RCT determined that "casinghead gas" produced from petitioners' oil wells qualified for sale as "new" gas under Section 103 of the NGPA, 15 U.S.C. 3313. Petitioners consequently sold the gas produced by these wells subject to a higher ceiling price, which, in May 1984, was $2.899 per MM Btu. Pet. App. D12-D13.

FERC's show cause order alleged that there was reason to believe that petitioners were perforating their wells above the gas-oil contact in the gas-bearing formations owned by Dorchester. The Commission's order further alleged that petitioners were diverting gas from Dorchester's gas proration units for sale in both intrastate and interstate commerce as "new" gas under the higher price ceilings established by Section 103 of the NGPA, despite the fact that Dorchester's gas units had been dedicated for sale in interstate commerce under the Commission's certificate of public convenience and necessity, subject to the price ceilings of "old" gas under Section 104 of the NGPA. Pet. App. A8-A9, D24-D26.

3. After an evidentiary hearing, the administrative law judge, in January 1985, issued a recommended decision, concluding that petitioners had diverted natural gas dedicated to interstate commerce, in violation of Section 7(b) of the Natural Gas Act of 1978, 15 U.S.C. 717f(b), and

[5] Sales from 20 of Dorchester's wells are regulated under Section 104 of the NGPA. Sales from the remaining 15 are regulated as "stripper wells" under Section 108 of the NGPA, 15 U.S.C. 3318, because of their declining production.

sold that gas at a price in excess of the lawful maximum price, in violation of Section 504(a)(1) of the Natural Gas Policy Act, 15 U.S.C. 3414(a)(1). Pet. App. D1-D71.[6]

The ALJ reviewed Dorchester's certificate of public convenience and necessity and the pertinent contracts that formed the basis of FERC's issuance of that certificate. These documents confirmed that all gas produced from Dorchester's reserves, except "casinghead gas," had been dedicated to interstate commerce. Pet. App. D55-D60. The ALJ then found that most of the gas petitioners claimed to be "casinghead gas" was in fact "dry gas" which otherwise would have been produced by Dorchester. *Id.* at D62-D63. In so finding, the ALJ followed Texas state law, which defined "casinghead gas" as "any gas and/or vapor indigenous to an oil stratum and produced from the stratum with oil." Pet. App. D60. Since the evidence showed that petitioners were producing gas from above the gas-oil contact, *i.e.*, were producing "dry gas" as opposed to "casinghead gas," and that petitioners were selling this gas as "new" gas under the higher ceiling prices of the NGPA, the ALJ concluded that petitioners were violating both the NGA and NGPA. *Id.* at D65-D69.

4. In an order issued on July 12, 1985, the Commission adopted the recommended decision of the ALJ "in its entirety, including all findings of fact and conclusions of law." Pet. App. B14. Accordingly, the Commission ordered petitioners immediately to "cease and desist from selling natural gas from their wells on the acreage subject

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[6] The ALJ found that 35 of the 37 named oil well operators had violated the NGA and/or the NGPA. She found that the evidence against the remaining two operators was inconclusive and required further investigation. Pet. App. A8. Only the 35 operators found to have violated federal law sought review before the court of appeals and are petitioners, along with the RCT, in this case. See *id.* at A9.

to this proceeding in the Panhandle West Gas Field." *Id.* at B15.[7]

In an order issued on November 13, 1985, the Commission denied petitioners' motions for a stay and requests for rehearing. Pet. App. C1-C36.

5. The court of appeals (Pet. App. A1-A41) denied petitions for review of the Commission's order filed by both the oil well operators and the RCT. The court first rejected petitioners' contention that the Commission had exceeded its jurisdiction. The court concluded that the Commission's actions did not impermissibly trench on state regulatory prerogatives under the NGA and the NGPA, particularly where, as here, the Commission must examine local well completion and perforation practices in order to determine whether gas producers are complying with those federal statutes. *Id.* at A15-A22. In a similar vein, the court dismissed petitioners' claim that the Commission, under the reasoning of *Burford* v. *Sun Oil Co.*, 319 U.S.

[7] The Commission also disposed of various procedural objections raised by individual petitioners that are no longer at issue. Pet. App. B6-B8.

With respect to the RCT's earlier request that the Commission stay its proceedings in order for the RCT to resolve certain potentially relevant state law issues, the Commission observed that steps taken by the RCT, including the issuance of a memorandum and letter to operators in the West Panhandle Field, together with applicable Texas statutes and field rules, confirmed that the Commission's decision was fully consistent with state law, and thus rendered a stay inappropriate. See Pet. App. B8-B13.

Finally, the Commission remanded the case to the ALJ for separate hearings regarding an appropriate remedy for petitioners' statutory violations. Pet. App. B15. After the court of appeals issued its decision, the Commission entered its remedial order requiring petitioners to pay monetary damages and restitution. See *Stowers Oil & Gas Co.*, 44 F.E.R.C. ¶ 61,128, on reh'g, 48 F.E.R.C. ¶ 61,230 (1989), appeal pending, *Northern Natural Gas Co.* v. *FERC*, No. 89-1512 (D.C. Cir.) (filed Aug. 24, 1989).

315 (1943), should have abstained from exercising its jurisdiction. As the court explained, the Commission "was clearly acting within its jurisdiction, and it was taking Texas statutes and regulatory determinations at their face value. A *federal* regulatory issue was the issue before FERC. This is not *Burford,* and FERC was not required to have deferred." Pet. App. A22-A23 (emphasis in original).

Turning to the merits of the Commission's order, the court of appeals found that there was "extensive evidence" supporting the determinations that petitioners "were producing gas from above the gas-oil contact," Pet. App. A24-A25, that this gas, which did not qualify as "casinghead gas" under Texas state law, had already been dedicated for sale in interstate commerce by virtue of Dorchester's certificate of public convenience and necessity, and that the gas thus could not be sold as "new" gas under the NGPA. *Id.* at A25-A31.

The court of appeals also rejected petitioners' contention that the Commission's decision impermissibly conflicted with the RCT's previous determination that petitioners' wells qualified for "new" gas status under Section 103 of the NGPA. In the court's view, the Commission had correctly determined that the RCT's Section 103 designations applied only to gas that was in fact "casinghead gas" from oil proration units, not to "dry gas" previously dedicated to interstate commerce. Pet. App. A31-A39.

Lastly, the court of appeals dismissed petitioners' claim that the Commission's show cause order "did not give them adequate notice of the theory under which FERC would proceed." Pet. App. A40. After reviewing the show cause order, the court concluded that it adequately notified petitioners that the concept of the gas-oil contact could become relevant in the proceedings. *Id.* at A41.

ARGUMENT

The decision of the court of appeals is correct. It does not conflict with any decision of this Court or of any other court of appeals. Accordingly, further review by this Court is not warranted.

1. Petitioners renew their contention (89-196 Pet. 16; 89-394 Pet. 9-10) that the Commission has exceeded its jurisdiction by trespassing on the States' exclusive authority to regulate "the production or gathering of natural gas" under Section 1(b) of the NGA, 15 U.S.C. 717(b). Congress, however, has vested the Commission with exclusive authority to enforce both the NGA and NGPA with respect to wellhead pricing and interstate sales of natural gas. See 15 U.S.C. 717 and 15 U.S.C. 3411. That is precisely what the Commission's order in this case accomplished; as the court of appeals explained, "[t]he Commission here was regulating the price ceilings of sales of natural gas in interstate commerce." Pet. App. A16. And, to the extent petitoners seek a safe harbor in the production or gathering exception of Section 1(b) of the NGA, that effort must fail. This Court has previously held that "sales in interstate commerce for resale by producers to interstate pipeline companies do not come within the 'production or gathering' exemption." *Phillips Petroleum Co.* v. *Wisconsin,* 347 U.S. 672, 680-681 (1954).

For similar reasons, the RCT (89-196 Pet. 15-16) errs in relying on decisions such as *Panhandle Eastern Pipe Line Co.* v. *TXO Prod. Corp.,* 34 F.E.R.C. ¶ 61,292, reh'g denied, 36 F.E.R.C. ¶ 61,182 (1986), and *Shell Oil Co.* v. *FERC,* 566 F.2d 536 (5th Cir. 1978), aff'd by an equally divided Court, 440 U.S. 192 (1979). In *Panhandle Eastern Pipe Line,* the Commission held that it lacked jurisdiction to prevent drainage of gas from a dedicated lease when actions in a non-dedicated adjoining lease (over which FERC

had no jurisdiction) caused such drainage. 34 F.E.R.C. ¶ 61,292, at 61,525. Here, by contrast, petitioners were withdrawing gas directly from Dorchester's dedicated lease – a lease plainly subject to the Commission's jurisdiction by virtue of the certificate of public convenience and necessity issued in 1954. And in *Shell Oil,* the Fifth Circuit overturned a Commission order assuming jurisdiction over production matters such as well completions. 566 F.2d at 539-541. In these proceedings, however, the Commission examined well completion practices only in the context of deciding the ultimate issues of interstate pricing and sales. Indeed, petitioners remain free to produce their oil and gas subject only to state law restrictions. The Commission held only that the gas they produce must be sold in accord with federal law.

2. Petitioners further claim (89-196 Pet. 17-20; 89-394 Pet. 10) that the Commission's order subjects oil operators to conflicting federal and state standards. According to petitioners, the Commission's application of a "rigid" gas-oil contact standard to determine whether gas is "dry" or "casinghead" conflicts with the RCT's more flexible approach that takes into account the gas-oil contact and other factors. However, the asserted conflict does not exist. As the court of appeals made plain (Pet. App. A28-A29), the Commission's decision followed settled Texas state law with respect to the treatment of the gas-oil contact in distinguishing between "dry" and "casinghead" gas.

Since 1933, the RCT has required all Texas oil well operators to establish the line of contact between their oil wells and gas-bearing rock formations (the "gas-oil contact"), and to perforate their oil wells only *below* the gas-oil contact. Pet. App. D8 (citing Texas Statewide Rule

13(b)(4)).[8] Here, the record shows that petitioners had extracted gas from the zone above the gas-oil contact. Indeed, the Commission specifically found that after petitioners had drilled their oil wells they made new perforations into gas-bearing rock. See, *e.g.*, Pet. App. D66-D67.

The Commission also applied express state law definitions in determining that the gas petitioners produced was "dry" gas, not "casinghead" gas. Under Texas law, gas produced from gas-bearing rock, "dry" gas, belongs to gas proration unit owners, not oil well operators. Tex. Nat. Res. Code Ann. §§ 86.002(7), 86.097 (Vernon 1978); see Pet. App. F16, F27. "Casinghead" gas, by contrast, which belongs to oil well operators, is "any gas or vapor indigenous to an oil stratum and produced from the stratum with oil." Tex. Nat. Res. Code Ann. § 86.002(10) (Vernon 1978); see Pet. App. F17.[9] Once again, substantial

[8] The RCT, in a recent decision, Oil and Gas Docket No. 10-87,017, observed that well operators may have difficulty in identifying the precise location of the gas-oil contact in any given well and that a 50-foot transition zone may sometimes exist between the gas and oil horizons. See 89-196 Pet. 18-19. Despite these observations, the RCT has not repealed its longstanding rule requiring well operators to establish the gas-oil contact. See Pet. App. D8 (citing Texas Statewide Rule 13(b)(4)). Thus, FERC may not be faulted for following that settled state law practice.

[9] Indeed, the Texas Supreme Court, in an analogous setting, has recently acknowledged the Commission's proper construction of these state law provisions. See *Amarillo Oil Co.* v. *Energ-Agri Products, Inc.*, No. C-6649 (Mar. 8, 1989).

The RCT (89-196 Pet. 19) also claims that the Commission, in determining that petitioners were producing gas from the dry gas horizon, used the wrong gas-oil ratio. That claim is not presented here. The Commission used the gas-oil ratio only during the damages proceedings, which are currently pending before the District of Columbia Circuit. See *Stowers Oil & Gas Co.*, 44 F.E.R.C. ¶ 61,128, on reh'g 48 F.E.R.C. ¶ 61,230 (1989), appeal pending, *Northern Natural Gas Co.* v. *FERC*, No. 89-1512 (D.C. Cir.) (filed Aug. 24, 1989); note 7, *supra*.

evidence supports the Commission's determination that the gas produced from petitioners' oil proration units was not a byproduct of drilling, and thus could not qualify as "casinghead gas." See, *e.g.*, Pet. App. C14, D66-67; see note 10, *infra*.

3. Petitioners also contend (89-196 Pet. 20-23; 89-394 Pet. 11-13) that the Commission's order conflicts with the RCT's previous determination that petitioners' wells qualified for "new" gas status under Section 103 of the NGPA. As the court of appeals correctly recognized (Pet. App. A31-A39), however, since the NGPA permits a state jurisdictional agency to grant Section 103 status only to wells that are *not* in an existing proration unit at the time, see, *e.g.*, 15 U.S.C. 3313(c), the RCT's Section 103 determinations plainly could not have applied to Dorchester's preexisting gas proration units.

As the court of appeals explained:

> Section 103 operates to prevent the petitioners from obtaining a section 103 price for natural gas produced from an existing Dorchester proration unit. The petitioners are entitled to a section 103 price for gas produced by their section 103 oil wells only when that gas is produced from their oil proration units and is therefore casinghead gas, that is gas "indigenous to an oil stratum and produced from the stratum with oil." Tex. Nat. Res. Code Ann. § 86.002(10). Such gas will be from below the gas oil contact and will not be part of Dorchester's dedicated reserves.

Pet. App. A38-A39. In other words, the Commission correctly "approached [the RCT's Section 103] determinations as administratively final * * * and did not attempt to make new section 103 determinations * * *. Instead, the

[Commission] undertook to ascertain [their] scope consistent with the federal statutory language." *Id.* at A21.[10]

4. Petitioners also renew their claim (89-394 Pet. 18-21) that the Commission's show cause order did not adequately notify them of the Commission's theory of liability, namely, that the gas-oil contact established the division between the gas-producing and oil-producing zones in the West Panhandle Field. As the court of appeals observed, "petitioners' contention overstates the case." Pet. App. A41. The Commission's show cause order, as the trigger to agency proceedings, must set forth the areas of inquiry. As such, the order does not limit the issues that parties may raise in those proceedings.

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[10] The record refutes the RCT's assertion (89-196 Pet. 19) that all the gas petitioners were extracting qualified as "casinghead" gas, *i.e.*, gas produced as a byproduct of oil drilling. The Commission specifically found that after petitioners had drilled their oil wells they made new perforations into gas-bearing rock. See Pet. App. D67. The Commission also found that, although Texas state law required well operators to find the gas-oil contact within each well, see *id.* at D8 (citing Texas Statewide Rule 13(b)(4)), "[s]everal [oil well operators] testified that they did not know or bother to ascertain where the gas-oil contact was in their particular wells." Pet. App. D66. Finally, the Commission credited testimony from geological and engineering experts that the gas produced by petitioners was not gas indigenous to an oil stratum and was not extracted from the stratum together with oil. See *id.* at D67. Accordingly, substantial evidence supports the Commission's decision that the gas was extracted from Dorchester's gas proration units and was not produced from petitioners' oil proration units as a byproduct of drilling. See *id.* at C14.

Petitioners assert (89-394 Pet. 17-18) that the Commission applied standards "retroactively" in this case when it determined that the gas at issue was Section 104 "dry" gas from Dorchester's gas proration units rather than Section 103 "casinghead" gas. That claim is meritless. The Commission's decision merely enforced previously established principles for determining the proper categorization of gas in the context of ensuring that gas is produced and sold in accord with federal law.

In this case, the show cause order, rather than presenting the Commission's theory of the case, explained that the Commission's proceeding would focus on allegations that "dedicated gas reserves have been and are being irrevocably drained from the interstate market and sold at unlawfully high rates." 26 F.E.R.C. ¶ 61,207 at 61,480 (1984). The order also made clear that it "neither makes findings of fact nor reaches conclusions of law with regard to the * * * alleged acts and practices." *Ibid.* The order thus plainly notified petitioners that, at the scheduled proceeding, the parties would be free to explore any facts or legal theories relating to the potential violations. Under these circumstances, the court of appeals correctly concluded that "the show cause order set the inquiry broadly enough to encompass the concept of the gas-oil contact." Pet. App A41 (internal quotation marks and citation omitted).[11]

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[11] Contrary to petitioners' assertions (89-196 Pet. 23; 89-394 Pet. 10), the court of appeals correctly held that the Commission had no obligation, under the circumstances presented, to abstain from exercising its regulatory jurisdiction. First, the record shows that the Commission gave the RCT ample opportunity to take action on its own. See Pet. App. B8-B13 (recounting procedural history). Second, the Commission could no longer defer action once it became clear that petitioners were committing ongoing violations of federal law. Third, as explained above, the Commission's decision specifically took into account state law requirements and is fully consistent with state law. Finally, as the court of appeals observed, the Commission

> was clearly acting within its jurisdiction, and it was taking Texas statutes and regulatory determinations at their face value. A *federal* regulatory issue was the issue before FERC. This is not *Burford* [v. *Sun Oil Co.*, 319 U.S. 315 (1943)], and FERC was not required to have deferred.

Id. at A23 (emphasis in original).

CONCLUSION

The petitions for a writ of certiorari should be denied.

Respectfully submitted.

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On Petition for a Writ of Certiorari to the United States Court of Appeals for the Tenth Circuit

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BRIEF IN OPPOSITION OF RESPONDENTS DORCHESTER MASTER LIMITED PARTNERSHIP, NATURAL GAS PIPELINE COMPANY OF AMERICA, AND NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

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QUESTIONS PRESENTED

1. Whether the Federal Energy Regulatory Commission's authority over interstate wholesale sales of natural gas empowered it to examine subsurface facts and state statutes and regulations in deciding whether certain sales were made in violation of the pricing provisions of the Natural Gas Policy Act and the abandonment provisions of the Natural Gas Act.

2. Whether a federal agency is required to defer its proceedings in favor of a state agency's proceedings where federal regulatory questions primarily are involved.

3. Whether an order to show cause, which made no findings of fact or conclusions of law, but which referred specifically to conduct later found to be lawful, gave the respondents named in that order adequate notice of the nature of the proceedings.

RULE 28.1 DISCLOSURE

A listing of parent companies, subsidiaries, and affiliates of respondents appears in the respondents' appendix at pages 1a to 8a.

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BRIEF IN OPPOSITION OF RESPONDENTS DORCHESTER MASTER LIMITED PARTNERSHIP, NATURAL GAS PIPELINE COMPANY OF AMERICA, AND NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

Dorchester Master Limited Partnership, Natural Gas Pipeline Company of America, and Northern Natural Gas Company, Division of Enron Corp., respondents in the captioned cases, respectfully request that this Court deny the petitions for a writ of certiorari to review the judgment of the United States Court of Appeals for the Tenth Circuit, which is reported at 874 F.2d 1320 (1988) (Pet. App. Vol. 1 at A1 to A41).

STATEMENT

One of Congress' responses to the natural gas shortage prevalent in the 1970s was enactment of the Natural Gas Policy Act of 1978 ("NGPA"), 15 U.S.C. §§ 3301 *et seq.* By establishing higher price ceilings for new gas, Congress sought to provide gas producers an economic incentive to find and develop new reserves. *See, e.g.*, H. Rep. No. 95-1752, 95 Cong. 2d Sess. at 68, 80, *reprinted at* 1978 U.S. Code Cong. & Admin. News 8983 at 8984-85, 8997. *See also* 123 Cong. Rec. 30373 (September 22, 1977). However, some producers, including the 34 oil well operators in this case,[1] attracted by the NGPA incentives, devised a scheme to sell old gas at the considerably higher NGPA new gas prices.

Typically, the oil operators secured oil leases on the same land in the Panhandle Field in Texas on which Dorchester Gas Producing Company ("Dorchester") also held gas leases and from which Dorchester had produced and sold "dedicated" natural gas pursuant to federal certificate authority for more than 35 years to Northern Natural Gas Company ("Northern"), an interstate pipeline; because such gas was classified under the NGPA as "committed or dedicated to interstate commerce," NGPA § 2 (18), 15 U.S.C. § 3301(18) (App. at 15a), it could be sold only at or below the low ceiling prices specified under NGPA § 104, 15 U.S.C. § 3314 (App. at 26a).[2]

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[1] Of the original 37 oil well operators named as respondents in the Federal Energy Regulatory Commission's show cause order, 34 are petitioners for writ of certiorari in No. 89-394. These 34 oil well operators and the Railroad Commission of Texas are referred to jointly as "petitioners" and individually as "RCT" and the "oil operators."

[2] For old gas qualifying under NGPA § 104, Congress retained the pricing structure developed under the Natural Gas Act ("NGA"), 15 U.S.C. §§ 717 *et seq.* As a result, there are 15 subcategories of prices under § 104. Most of the gas sold by Dorchester to Northern qualifies as "flowing gas—large producer," although some of Dorchester's gas also qualifies under NGPA § 108, 15 U.S.C. § 3318 (App. at 29a), as "stripper well natural gas." *See also* 18 C.F.R. § 271.101 (App. at 49a).

The oil operators generally completed their wells initially in the granite wash or fractured granite formations (the deepest formations in the field), produced small amounts of oil and casinghead gas, classified the wells as oil wells,[3] and claimed entitlement to NGPA § 103 prices, 15 U.S.C. § 3313 (App. at 24a). Then, these producers later would perforate the shallower brown dolomite formation, the main gas-bearing formation, which was (and is) the sole source tapped by Dorchester's wells, produce vastly greater volumes of gas, and claim that the wells were producing additional "casinghead gas" for which they also would charge their purchasers § 103 prices.[4] The problem was that the gas they took from the dolomite formation and sold mainly to intrastate purchasers was the same gas that otherwise would have been produced by a Dorchester gas well and sold to Northern at the lower § 104 prices applicable to dedicated gas.[5]

After a preliminary investigation by its Enforcement Staff, the Federal Energy Regulatory Commission

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[3] An operator obtains an oil well classification simply by filing a self-certifying Form W-2 with the RCT.

[4] Thirty-four of the original 37 oil operators made sales to intrastate purchasers, while three made sales exclusively to Northern. In all instances, however, the sales prices exceeded the limits of NGPA § 104.

[5] Under Texas law, an oil well must produce at least one barrel of oil for every 100,000 cubic feet of gas. Tex. Nat. Res. Code Ann. § 86.002(b) (Vernon 1978) (Pet. App. Vol. 3 at F-16). Because many Panhandle Field oil wells produced very little or even no oil, some operators, including 28 involved in this proceeding, installed refrigeration or low temperature extraction (LTX) units on their leases. By cooling the gas produced by these "oil" wells, the refrigeration units manufactured natural gas liquids. The operators counted these manufactured liquids (sometimes called "white oil") as crude oil in order to obtain or maintain their oil well classifications. In 1985, the RCT banned the counting of the liquid product of refrigeration units as crude oil for well classification purposes. RCT Oil and Gas Docket No. 10-77,314, Final Order (May 13, 1985). The RCT's order was upheld on appeal. *Hufo Oils v. Railroad Comm. of Texas*, 717 S.W.2d 405 (Tex. App. Austin 1986), *writ denied* (March 22, 1989).

("FERC") ordered the oil operators to show cause why they should not be held in violation of the pricing provisions of NGPA § 504, 15 U.S.C. § 3414 (App. at 39a), and the abandonment provisions of NGA § 7(b), 15 U.S.C. § 717f(d) (App. at 10a), by virtue of their sales of dedicated gas to third parties. *Stowers Oil & Gas Co.*, 26 FERC (CCH) ¶ 61,207 (1984) (App. at 51a). After full public hearings, the presiding administrative law judge ("ALJ") decided on the basis of "overwhelming" evidence, 30 FERC (CCH) ¶ 63,017 at 65,048, that the oil operators were violating those statutes and ordered them to cease their violations. 30 FERC (CCH) at 65,049. In Opinion No. 239, FERC affirmed the ALJ's recommended decision. 32 FERC (CCH) ¶ 61,043 at 61,136. Requests for rehearing and stay later were denied. 32 FERC (CCH) ¶ 61,207 at 61,427. By determining that statutory violations had occurred, FERC concluded Phase 1 of the case. FERC then began Phase 2 to decide how those violations should be remedied.

On review, the United States Court of Appeals for the Tenth Circuit affirmed FERC's Phase 1 orders in full. *Walker Operating Corp. v. FERC*, 874 F.2d 1320 (10th Cir. 1989). No Phase 2 orders were before the court.[6]

1. FERC Opinion No. 239

In Opinion No. 239, FERC made three findings on which its decision rested: (1) any casinghead gas sold by the oil operators is not dedicated to interstate commerce, but all other gas sold from their wells is so dedicated, 30 FERC (CCH) at 65,046; (2) only casinghead gas sold by the oil operators qualifies for incentive pricing under NGPA § 103, 30 FERC (CCH) at 65,047; and

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[6] FERC only recently issued its order on rehearing in Phase 2. *Stowers Oil & Gas Co.*, 48 FERC (CCH) ¶ 61,230 (Opinion No. 307-A 1989), *appeal docketed sub nom., Northern Natural Gas Co. v. FERC*, No. 89-1512 (D.C. Cir. Aug. 24, 1989); *Texaco Producing Inc. v. FERC*, No. 89-1593 (D.C. Cir. Sept. 22, 1989); and *Stowers Oil & Gas Co., et al. v. FERC*, No. 89-4701 (5th Cir. Sept. 14, 1989).

(3) most of the gas the oil operators sold was not casinghead gas. 30 FERC (CCH) at 65,048.

Under NGPA § 601(a)(1)(A), 15 U.S.C. § 3431(a)(1)(A) (App. at 44a), FERC retains jurisdiction over gas committed or dedicated to interstate commerce before the Act was passed, but only to the extent that such gas does not qualify for incentive pricing under NGPA §§ 102(c), 103(c) or 107(c)(1), (2), (3), or (4), 15 U.S.C. §§ 3312(c), 3313(c), 3317(c)(1), (2), (3), or (4) (App. at 17a, 24a, and 27a). Thus, the issue of what gas remains subject to FERC's NGA jurisdiction is dependent in the first instance upon the coverage of a given well category determination. The scope of the oil operators' well category determinations accordingly was the primary focus of the proceeding.[7]

The oil operators sought and received NGPA § 103 well category determinations for their sales of casinghead gas. In obtaining these determinations, the oil operators certified, among other things, that their wells were not completed within an existing proration unit, *i.e.*, that each of their oil wells was the first well in a new proration unit. NGPA § 2(8)(A), 15 U.S.C. § 3301(8)(A) (App. at 14a), defines "proration unit" as "any portion of a reservoir, as designated by the State [regulatory] . . . agency . . ., which will be effectively and efficiently drained by a single well." In light of this provision, FERC not only was authorized to look to Texas law and RCT regulations to ascertain the scope of the oil operators' § 103 well category determinations, it was required to do so.

The result of FERC's review of applicable Texas law and regulations was the conclusion that the State had vertically divided the reservoir into two distinct proration units: (1) the portion of the reservoir effectively and efficiently drained by an oil well, *i.e.*, the oil and casinghead gas producing portion, which lies at or below the

[7] The NGPA § 103 issue is the only one which affects all oil operators who were show cause respondents before FERC and are petitioners for certiorari.

gas-oil contact; and (2) the portion of the reservoir effectively and efficiently drained by a gas well, *i.e.*, the gas-only producing portion, which is situated above the gas-oil contact. 30 FERC (CCH) at 65,048.

Once the scope of the well category determinations was identified, *i.e.*, embracing only casinghead gas, 30 FERC (CCH) at 65,047, FERC—as part of its enforcement responsibility—undertook to determine whether as a factual matter the gas volumes sold by the oil operators at § 103 prices were covered by their § 103 well category determinations, *i.e.*, the extent to which the oil operators sold casinghead gas.

FERC found that most of the gas sold by the oil operators was not casinghead gas but was gas produced from above the gas-oil contact from the gas-only producing portion of the reservoir. Thus, the gas sold by the oil operators at § 103 prices was not produced from the new proration units assigned to their oil wells but from the existing proration units assigned to Dorchester's gas wells. 30 FERC (CCH) at 65,048. Once this fact was established, Texas law essentially became immaterial to the § 103 inquiry. In other words, where a second well is completed in an existing proration unit, gas produced from that proration unit by the second well is ineligible for § 103 pricing unless the state agency explicitly finds that the second well was necessary to effectively and efficiently drain the proration unit. NGPA § 2(8), 15 U.S.C. § 3301(8) (App. at 14a); 18 C.F.R. § 271.305 (App. at 49a). As the RCT did not make that finding for any of the oil operators' wells, 30 FERC (CCH) at 65,047, there was no conceivable basis to support § 103 pricing for the gas the oil operators produced and sold from the existing proration units assigned to the Dorchester gas wells.

Whether sales of such gas to intrastate buyers also constituted unlawful diversions in contravention of NGA § 7(b) depended on whether that gas previously was dedicated to interstate commerce. Resolution of the latter

question necessarily entailed examination of Dorchester's certificate and its 1952 contract covering the sale of gas to Northern. FERC's review of these documents resulted in its conclusion that all gas other than casinghead gas was dedicated to interstate commerce. 30 FERC (CCH) at 65,046. This conclusion was not challenged below.

Having determined the scope of dedication was all gas other than casinghead gas, it was incumbent on FERC to decide whether the gas sold to intrastate purchasers was in fact casinghead gas. Consulting Texas law and RCT regulations, 30 FERC (CCH) at 65,046, for federal law purposes, FERC adopted verbatim the State's statutory and regulatory definition of casinghead gas: "any gas or vapor indigenous to an oil stratum and produced from the stratum with oil." Tex. Nat. Res. Code Ann. § 86.002 (10) (Vernon 1978) (Pet. App. Vol. 3 at F-17); Title 16, Texas Admin. Code § 3.69 (Pet. App. Vol. 3 at G-22). Gas satisfying the definition must by necessity be produced from completion locations at or below the gas-oil contact. As noted above, FERC found that most of the gas sold by the oil operators was not casinghead gas produced from completion locations at or below the gas-oil contact but the same gas that otherwise would have been produced by Dorchester's gas wells. As all gas other than casinghead gas was dedicated to interstate commerce under the NGA, gas other than casinghead gas could not be sold to a purchaser except Northern without FERC's prior approval under NGA § 7(b); the oil operators' sales of such gas to intrastate purchasers therefore were held to violate NGA § 7(b). 30 FERC (CCH) at 65,048.

2. The Court of Appeals Decision

In its unanimous decision affirming Opinion No. 239, the three-judge panel of the Tenth Circuit first addressed the oil operators' and aligned petitioners' jurisdictional arguments. The court traced the demarcation of authority between federal and state agencies concerning natural gas regulation from pre-NGA times through post-NGPA decisions of this Court. 874 F.2d at 1325-28. Focusing

on NGA § 1(b), 15 U.S.C. § 717(b) (App. at 9a), the court of appeals observed that state regulation under the "production or gathering" exemption does not bar legitimate federal regulatory action clearly delegated to FERC by Congress. Indeed, the court noted that comprehensive federal authority over prices paid for gas producers' interstate sales was preserved by the NGPA, *i.e.*, the NGPA did not augment the authority of states in this area. 874 F.2d at 1327.

Considering in this context the oil operators' contention that NGA § 1(b) barred FERC from ascertaining the scope of their well category determinations and of Dorchester's certificate, the court rejected this argument because in so acting FERC was engaged in an undeniably legitimate activity: "regulating the price ceilings of sales of natural gas in interstate commerce." 874 F.2d at 1328. In this respect, the court found that the ALJ's examination of geological and other subsurface factors, pertinent contracts, Texas statutes, and RCT regulations was necessary background for application of relevant federal statutes and therefore within FERC jurisdiction. 874 F.2d at 1328-30.

To the oil operators' argument that even if it had jurisdiction, FERC, under *Burford v. Sun Oil Co.*, 319 U.S. 315 (1943), should have abstained in deference to Texas forums, the court responded that because here, unlike *Burford*, a federal regulatory issue was being resolved, abstention was unnecessary. 874 F.2d at 1330-31. Further, the court found that FERC merely was taking the Texas statutes and regulations at face value, and as a matter of fact did stay its proceedings to allow the RCT time to decide certain state law questions. 874 F.2d at 1330-31 and n. 14.

The court of appeals next rejected the oil operators' attacks on the evidentiary sufficiency for FERC's findings of fact, including the finding that the oil operators were selling gas produced from above the gas-oil contact (a predicate for the conclusion that most of the gas they were selling was dedicated gas from a Dorchester prora-

tion unit). The court found no basis for questioning FERC's finding that the evidence was "totally persuasive," resting on "accepted scientific principles of geology, chemistry and reservoir engineering." The court thus ruled that FERC's factual findings satisfied the statutory substantial evidence standard of review. 874 F.2d at 1331-32.[8]

Reviewing the oil operators' claim that FERC drew erroneous conclusions regarding Texas law, the court held that FERC acted reasonably in adopting verbatim the definition of casinghead gas from the relevant Texas statute and regulation and in using a gas-oil contact to determine whether casinghead gas was being sold. In these respects, the court found overwhelming support for FERC's definitional position, including persuasive expert scientific and engineering testimony, recent Texas judicial opinions, and the January 1989 Final Order in the RCT's Panhandle Field proceedings. 874 F.2d at 1332-34.

The court then rebuffed the oil operators' argument that all gas they produced was removed by NGPA § 601 from FERC jurisdiction because their wells were determined by the RCT to be NGPA § 103 wells. The court reasoned that FERC properly regarded those well category determinations as valid to the extent they covered casinghead gas. However, FERC's conclusion that those determinations could not remove dedicated gas from NGA jurisdiction also was proper, the court said, because the NGPA precludes § 103 prices attaching to gas sold from a well located within a preexistent proration unit. As the oil operators were producing gas from locations within Dorchester's proration units, such gas was not entitled to § 103 treatment, either for pricing or jurisdictional purposes, the court found. 874 F.2d at 1334-36.

Additionally, the court addressed the oil operators' contention that all their gas was § 103 gas because of the

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[8] Petitioners for certiorari do not seek review of this conclusion.

RCT's alleged implicit finding that their wells were necessary to effectively and efficiently drain Dorchester's proration units. Because the applicable federal regulation requires any such finding to be explicit, and as no explicit finding was made, the court dismissed this argument. 874 F.2d at 1336-37.[9]

After affirming FERC's conclusions of law on the basis of NGPA legislative history and other factors, 874 F.2d at 1337, and approving FERC's reasoning process as having articulated clearly a rational connection between its findings and conclusions, 874 F.2d at 1337-38, the court examined the oil operators' allegations of procedural unfairness. At issue was interpretation of the scope of FERC's show cause order. The court agreed with FERC's position that because the show cause order referred, among other things, to the levels at which the oil operators perforated their wells, the inquiry was set broadly enough to encompass the concept of the gas-oil contact; the oil operators thus were held to have had adequate notice of the theory under which FERC proceeded. 874 F.2d at 1338.

REASONS WHY THE PETITIONS SHOULD BE DENIED

I. Petitioners do not raise any special and important reasons justifying this Court's review of the court of appeals decision.

Under Rule 17.1 of this Court's rules, review on writ of certiorari is a matter of judicial discretion, to be granted only when there exist "special and important" reasons calling for the exercise of the Court's supervisory powers. Although petitioners make passing reference to reasons for granting the writ,[10] those reasons go largely unexplained. Instead, petitioners simply reargue the merits of issues addressed by both FERC and the court of appeals. While those issues may have sub-

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[9] Petitioners for certiorari do not seek review of this conclusion.

[10] RCT at 4-6; the oil operators incorporate by reference the reasons advanced by the RCT. Oil Operators at 8.

stantial importance to the particular parties involved in the proceedings below, petitioners have not demonstrated, nor can they demonstrate, that those issues are of such wide import under the Constitution or laws of the United States that a grant of plenary review of the decision of the court of appeals is necessary.

The decision of the court of appeals does not conflict with the decisions of any other court of appeals, any state court, or this Court. Similarly, the decision of the court of appeals does not conflict with FERC's orders; the court of appeals affirmed the agency in all respects. This case presents no important constitutional questions, nor does it raise any important federal questions nor any questions that are likely to arise again. In fact, this case is somewhat of an historical anomaly. The leasing practices that resulted in the severance of the gas and oil interests that, in turn, resulted in gas and oil wells occupying the same surface acreage, were peculiar to the Panhandle Field. More importantly, Congress recently passed legislation that eventually eliminates all wellhead natural gas price controls as well as FERC's remaining certificate and abandonment authority over wellhead natural gas sales. Natural Gas Decontrol Act of 1989, Pub. L. 101-60 (July 26, 1989). The economic incentive to disguise old gas as new no longer exists, and in the future FERC may not have occasion to enforce NGPA § 504 or NGA § 7(b) as it did in the proceedings below.[11]

II. Court decisions regarding § 1(b) of the Natural Gas Act do not need clarification.

The RCT argues this Court should review the judgment of the court of appeals because "the courts have not clearly defined the line of demarcation between federal and state jurisdiction" under § 1(b) of the NGA. RCT at 4. The RCT does not identify the decisions that

[11] Decisions by state courts regarding title to casinghead and non-casinghead gas and by the RCT regarding the use of refrigeration units also have discouraged conduct similar to that of the oil operators in this case.

require such clarification or explain why they are not clear but instead quotes a number of cases in which the courts have delineated very specifically the scope of FERC's and the states' authority under § 1(b), including this Court's recent decision in *Northwest Central Pipeline Corp. v. State Corp. Comm. of Kansas*, —— U.S. ——, 109 S. Ct. 1262 (1989). Thus, rather than pointing out any ambiguity in prior decisions of this Court or the courts of appeals, the RCT proceeds to argue the merits of the question whether FERC overstepped its jurisdictional boundary.

Under § 1(b) of the NGA, FERC has exclusive jurisdiction over, among other things, "the sale in interstate commerce of natural gas for resale." 15 U.S.C. § 717(b) (App. at 9a). FERC's Natural Gas Act jurisdiction encompasses regulation of market entry and exit through FERC's power to issue certificates of public convenience and necessity and to authorize the abandonment of certificated service. NGA § 7, 15 U.S.C. § 717f (App. at 10a). FERC's powers also extend to enforcing the wellhead price ceilings established under Title I of the NGPA. NGPA § 504, 15 U.S.C. § 3414 (App. at 39a). However, FERC's jurisdiction does not extend to the "production or gathering" of natural gas, a regulatory role reserved to the states." *Northwest Central Pipeline Corp.*, 109 S.Ct. at 1271-72.[12]

As recognized by the court of appeals, FERC's Opinion No. 239 properly addressed questions of pricing, dedication, and abandonment arising under the NGA and NGPA. In discharging its statutory responsibilities, FERC examined the geology of the field, information re-

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[12] Although *Northwest Central* is a useful guide to the meaning and scope of NGA § 1(b), it is not analogous to the FERC proceedings below. In *Northwest Central*, the Kansas Supreme Court held that a Kansas Corporation Commission proration order was not preempted by federal law and this Court affirmed. Here, neither FERC nor the 10th Circuit determined whether the NGA or NGPA preempted any state statute, regulation, or RCT order. FERC referred to and utilized state law in ruling on questions of federal law within its exclusive jurisdiction.

lating to the production of gas by both Dorchester and the oil operators, and various state statutes, rules, and regulations. Petitioners seize on the scope of FERC's evidentiary inquiry as proof that the agency violated the "production or gathering" exemption of NGA § 1(b). RCT at 15-16. This argument misstates the law and mischaracterizes FERC's decision.

FERC's inquiry into Panhandle Field geology, gas production, and matters of state law arose primarily for two reasons. First, as explained *supra* at pp. 5-6, the major focus of the FERC proceeding was the scope of the oil operators' § 103 well category determinations. Because the term "proration unit" as used in NGPA § 103 is defined in terms of state law, FERC correctly deferred to Texas law on this issue. In addition, in deciding as a factual matter whether the gas sold by the oil operators at § 103 prices was covered by their § 103 well category determinations, FERC necessarily examined well completion and production information. Second, the oil operators attempted to justify their actions in significant part on their purported compliance with state law.[13] By seeking to shield their activities from federal scrutiny by relying on their own interpretation of state law, the oil operators invited FERC to test the validity of their posi-

[13] For example, the oil operators relied on the "oil well defense." They reasoned: Our § 103 determinations cover casinghead gas. Under state law, casinghead gas is all gas produced from an oil well. Therefore, our § 103 determinations must cover all gas produced from our oil wells. FERC refuted this argument, as have the RCT and the Texas state courts (*see Amarillo Oil Co. v. Energy-Agri Products, Inc.*, 1989 Westlaw 19057, No. C-6649 (Tex. March 8, 1989); *Dorchester Gas Producing Co. v. Harlow Corp.*, 743 S.W.2d 243, 250-251, 258 (Tex. App. Amarillo 1987), *writ denied* (March 22, 1989); RCT Oil and Gas Docket No. 10-87,017, Amended Final Order Adopting and Clarifying Rules and Regulations for the Panhandle Carson County Field etc. (March 20, 1989) ("Final Order") *appeal docketed sub nom., Texaco Inc. v. RCT* Cause No. 465642 (98th District Court, Travis County, Texas) (Pet. App. Vol. 3 at E-1 to E-34)); and instead looked to the Texas statutory definition of casinghead gas to determine what is and what is not casinghead gas.

tion. However, FERC's examination of Texas law and facts about Panhandle Field geology and wells hardly constitutes federal regulation of production prohibited by NGA § 1(b). To the contrary, FERC specifically deferred to and accommodated the RCT's regulation of production, and FERC's decision is limited to matters of wellhead sales, dedication, and abandonment under its separate and exclusive federal jurisdiction.

FERC did not intrude into an area reserved to the states merely because facts concerning production activities were adduced and considered in the course of deciding whether producers violated NGA § 7(b) or NGPA § 504. In a host of cases regarding, for example, unlawful abandonment,[14] lease sales,[15] area and national rates,[16] pipeline rates and certificates,[17] and many other matters,[18] the production or gathering exemption of NGA § 1(b) has not been an impediment to FERC's examination of

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[14] *United Gas Pipe Line Co. v. McCombs*, 442 U.S. 529 (1979); *San Salvador Development Co.*, 59 FPC 2262, 2266 (1977); *Sun Oil Co.*, 56 FPC 3735, 3742 (1976); *Cities Service Gas Co.*, 38 FPC 364, 411-414 (1967).

[15] *United Gas Improvement Co. v. Continental Oil Co.*, 381 U.S. 392 (1965); *El Paso Natural Gas Co. v. Sun Oil Co.*, 708 F.2d 1011 (5th Cir. 1983); *Continental Oil Co. v. FPC*, 370 F.2d 57 (5th Cir. 1966), *cert. denied*, 388 U.S. 910 (1967).

[16] *See, e.g., Area Rate Proceeding (Permian Basin)*, 34 FPC 159, 189, 322, and 357 (Opinion No. 468 1965), *aff'd, Permian Basin Area Rate Cases*, 390 U.S. 747 (1968); *Area Rate Proceeding (Southern Louisiana Area)*, 40 FPC 530, 791-796 (Opinion No. 546 1968), *Southern Louisiana Area Rate Cases*, 428 F.2d 407 (5th Cir.), *cert. denied*, 400 U.S. 950 (1970); *Area Rate Proceeding (Hugoton-Anadarko Area)*, 44 FPC 761, 828, 939 (Opinion No. 586 1970), *aff'd Hugoton-Anadarko Area Rate Case*, 466 F.2d 974 (9th Cir. 1972).

[17] *Columbia Gas Transmission Corp.*, 10 FERC (CCH) ¶ 63,025 (1977), *rev'd on other grounds*, 10 FERC (CCH) ¶ 61,124 (1980); *Columbia Gas Transmission Corp.*, 56 FPC 1083 (1976); *Northern Natural Gas Co.*, 53 FPC 776, 781 (1975).

[18] *Union Oil Co. of California v. FPC*, 542 F.2d 1036 (9th Cir. 1976); *Superior Oil Co. v. FERC*, 563 F.2d 191, 196 (5th Cir. 1977).

information about subsurface facts, including geology and reservoir characteristics, and production activities. The oil operators cannot escape the consequences of their unlawful acts under federal law by claiming the production and gathering exemption makes those acts immune from FERC examination; NGA § 1(b) is not a refuge for illegal practices.

The RCT's citations to *Shell Oil Co. v. FERC*, 566 F.2d 536 (5th Cir. 1978), *aff'd*, 440 U.S. 192 (1979), and *Panhandle Eastern Pipe Line Co. v. TXO Production Corp.*, 34 FERC (CCH) ¶ 61,292 (1986), *reh'g denied*, 36 FERC (CCH) ¶ 61,182 (1986), do not support petitioners' § 1(b) arguments. RCT at 15. Unlike in *Shell*, in which FERC's predecessor, the Federal Power Commission, attempted to implement a rule requiring producers to maintain production capability in a certain manner, Opinion No. 239 does not prescribe or dictate the oil operators' drilling, completion, or production practices.[10] FERC did, however, prescribe the pricing consequences and service obligations that attach as a matter of federal law to the gas sold by the oil operators from their Panhandle Field wells. In *Panhandle*, FERC refused to entertain the pipeline's complaint because, unlike this case, the gas at issue was not committed or dedicated to interstate commerce. Furthermore, *Panhandle* did not involve any NGPA pricing questions as this case does.

A further extension of petitioners' NGA § 1(b) argument is their contention that FERC should have deferred to state tribunals on questions of state law. Although in the proceedings below it was never entirely clear to whom FERC should have deferred, presumably petitioners

[10] The RCT incorrectly states that "[m]ost, if not all of the acts and practices which FERC found to be illegal involve the 'drilling and spacing of wells and the like' . . . . The illegal acts cited by FERC involved completion techniques, perforation practices, well spacing, well classification, and related matters" (citation omitted). RCT at 16. FERC made no such findings nor did it cite to any such "illegal" acts.

would have had FERC wait for the conclusion of the various title actions in the state courts or the RCT's separate proceedings. Petitioners' arguments are founded on erroneous factual and legal premises.

The RCT incorrectly says FERC adjudicated and decided state law issues. RCT at 24. FERC applied state law as appropriate in deciding federal law questions. Further, the RCT asserts that the Texas law to which FERC referred was "unresolved." RCT at 23.[20] FERC, however, found state law to be unambiguous, as have the court of appeals, the state courts, and the RCT.[21] The RCT also contends that the "same and related issues were pending before Texas state courts and the [RCT]." RCT at 24. Again, the RCT is incorrect. As discussed more fully *infra* at pp. 20-24, FERC, the courts, and the RCT each addressed separate issues under each tribunal's separate and exclusive jurisdiction.

The RCT also has misapplied the law regarding abstention. Abstention is an extraordinary and narrow exception to the duty of a federal court (or, in this instance, federal agency) to adjudicate a controversy properly before it. Only in a few very limited, exceptional circumstances is deferral to a state tribunal warranted. *Colorado River Water Conservation District v. U.S.*, 424 U.S. 800, 813-124 (1976); *Ramos v. Lamm*, 639 F.2d 559, 564 (10th Cir. 1980), *cert. denied*, 450 U.S. 1041 (1981). As stated in *Baggett v. Bullitt*, 377 U.S. 360, 375 (1964):

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[20] However, even if FERC found that there is a genuine ambiguity in Texas law (which it did not), the clarification of which may conflict with subsequent state interpretations, abstention still is unwarranted. "The mere potential for conflict in the results of adjudication, does not, without more, warrant staying the exercise of federal jurisdiction." *Colorado Water Conservation District v. U.S.*, 424 U.S. 800, 816 (1976). *See also Zablocki v. Redhail*, 434 U.S. 374, 380 n.5 (1978) ("There is, of course, no doctrine requiring abstention merely because resolution of a federal question may result in the overturning of a state policy.").

[21] *See* n.13, *supra* at p. 13.

> The abstention doctrine is not an automatic rule applied whenever a federal court is faced with a doubtful issue of state law; it rather involves a discretionary exercise of a court's equity powers.

Here, the decision to abstain in deference to state tribunals is committed to the discretion of FERC.

Abstention may be appropriate if a state court determination of pertinent state law will moot the federal issues. *Colorado River Water Conservation District*, 424 U.S. at 184. That situation does not exist here. Title decisions by the courts will not resolve the NGA and NGPA questions adjudicated by FERC. Deferral to the RCT likewise would have been inappropriate. No RCT proceeding, past or present, could have mooted the dedication and pricing issues arising under the NGA and NGPA. The principal question facing the RCT in its proceeding regarding refrigeration units was whether natural gasoline manufactured by those units could be counted as crude oil for well classification purposes. *See Hufo Oils v. Railroad Commission of Texas*, 717 S.W.2d at 407. Although some of the operators involved in the FERC proceeding utilized refrigeration units, others did not, and the propriety of the use of refrigeration units was never an issue before FERC.[22] More importantly, even had the RCT sanctioned the use of refrigeration units for well classification purposes, FERC still would have been faced with the identical dedication and pricing questions.[23] Nor can RCT Docket No. 10-87,017 be used

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[22] *Stowers Oil & Gas Co.*, 27 FERC (CCH) ¶ 63,048 at 65,189 (1984) ("I definitely do not intend for this proceeding to duplicate the litigation before the Texas Railroad Commission . . . on the legality of counting extracted natural gas liquids as crude oil in calculating gas-oil ratios."). App. at 69a, 71a.

[23] It is important to note that even though the RCT commenced its inquiry into the refrigeration unit question in 1981, several years before the FERC proceeding, the RCT was not a party to the FERC proceeding until after FERC had rendered its decision in 1985. The RCT specifically informed the Texas Attorney General in 1984 that it did not wish to participate before FERC. Even after requesting FERC to refrain from issuing Opinion No. 239,

to bolster petitioners' deferral arguments. That proceeding was convened in 1986 to determine whether the Panhandle Field rules should be changed prospectively. Prospective changes in the field rules have no bearing on the oil operators' past practices.

Simply because FERC discussed and referred to state statutes and regulations does not justify abstention. As stated by this Court in *Ramos*:

> It is true . . . that the district court did discuss and interpret several state statutes . . . . However, resolution of these state law questions does not mandate the conclusion that the district court should have abstained from deciding this case . . .

639 F.2d at 564 (citations omitted). Moreover, the "mere difficulty of state law does not justify a federal court's relinquishment of jurisdiction." *Louisiana Power & Light Co. v. City of Thibodeaux*, 360 U.S. 25, 27 (1959). Indeed, this Court recently observed that:

> While *Burford* is concerned with protecting complex state administrative processes from undue federal interference, it does not require abstention whenever there exists such a process, or even in all cases where there is a "potential for conflict" with state regulatory law or policy. *Colorado River Water Conservation Dist.*, 424 U.S. at 815-816.

New Orleans Public Service, Inc. v. Council of City of New Orleans, ——— U.S. ———, 109 S. Ct. 2506, 2514 (1989). Nor is abstention required simply because a state court could entertain the same issues as the federal forum. *Ramos v. Lamm*, 639 F.2d at 564. Only where local interests predominate when compared to federal interests should the federal tribunal step aside. *Robert-Gay Energy Enterprises v. State Corp. Comm.*, 753 F.2d 857 (10th Cir. 1985).

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the RCT declined FERC's invitation to explain how FERC's ruling would affect the RCT's responsibilities. 32 FERC (CCH) ¶ 61,043 at 61,134. FERC certainly did not abuse its discretion for failing to defer to a state agency when that agency refused to inform FERC as to why it should defer.

Unlike *Burford v. Sun Oil Co.*, 319 U.S. 315 (1943), and its progeny as cited by petitioners, the federal government obviously has a substantial, legitimate interest in the enforcement of the NGA and NGPA.[24] The NGA and NGPA represent a comprehensive regulatory scheme, and Congress preempted any conflicting state law or regulation. *Northern Natural Gas Co. v. State Corp. Comm.*, 372 U.S. 84 (1963); *Transcontinental Gas Pipe Line Corp. v. State Oil & Gas Board*, 474 U.S. 409 (1986). The state may not encroach, even through conservation measures, upon preemptive federal legislation. *Oklahoma v. FERC*, 494 F. Supp. 636 (W.D. Okla. 1980), *aff'd*, 661 F.2d 832 (10th Cir. 1981), *cert. denied*, 457 U.S. 1105 (1982). Thus, when faced with dedication and pricing issues arising under the NGA or NGPA, courts frequently refer those matters to FERC as the agency with primary jurisdiction. *Texas Oil & Gas Corp. v. Michigan Wisconsin Pipe Line Co.*, 601 F.2d 1144 (10th Cir.), *cert. denied*, 444 U.S. 991 (1979); *Texas Oil & Gas Corp. v. Valley Gas Transmission, Inc.*, 608 F.2d 231 (5th Cir. 1979).

The issues confronting FERC—dedication and pricing—are central to FERC's statutory responsibilities. All "first sales" of natural gas, both in interstate and intrastate commerce, fall under FERC scrutiny. *See* NGPA §§ 2(21) and 504, 15 U.S.C. §§ 3301(21) and 3414. (App. at 16a and 39a). In addition, committed or dedicated gas remains subject to FERC's jurisdiction unless and until it is removed from that status by NGPA 601, 15 U.S.C. § 3431 (App. at 44a). FERC properly went forward to decision on these federal law issues and did

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[24] For example, in *Burford*, Sun Oil Co. attacked the validity of an RCT order granting Burford a drilling permit by bringing an injunctive action in federal district court. Jurisdiction of the federal court was invoked because of diversity of citizenship and because of a claimed denial of due process of law. No other federal interest was alleged. By contrast, FERC did not attempt to enjoin any action by the RCT or the state courts; FERC acted to enforce federal law and protect federal rights.

not abuse its discretion in declining to defer to state authorities.

Finally, the RCT's deferral argument is now moot. Since FERC's orders were issued in 1985, both the state courts and the RCT have issued decisions in the proceedings to which FERC supposedly should have deferred. Those decisions are entirely consistent with FERC's actions. Thus, if FERC had deferred and then later addressed the NGA and NGPA issues identified in the show cause order, that later result would have been the same as the result reached in Opinion No. 239.

III. Opinion No. 239 does not conflict with Texas law or the RCT's regulation of the Panhandle Field.

The RCT makes the bald assertion that FERC improperly interpreted Texas law and that FERC's interpretation conflicts with its own. RCT at 17-20. Yet despite the numerous state court and regulatory proceedings involving the Panhandle Field that have come to final resolution over the past several years, the RCT does not cite any decision that even suggests a conflict between it and Opinion No. 239. The reason for this is simple: There are none. This also was the conclusion of the court of appeals. 874 F.2d at 1334-35.

The same or similar facts that gave rise to FERC's show cause proceeding also gave rise to title suits in state and federal courts, primary involving gas rights owners (such as Dorchester) suing oil operators for conversion of natural gas, as well as to two separate regulatory proceedings before the RCT, one involving the refrigeration unit question, discussed *supra* at p. 3 n.5, and the other involving prospective changes to the Panhandle Field rules.[25] Each of these bodies, however, acted within its own exclusive sphere of jurisdiction: FERC over questions of pricing and dedication to interstate commerce; the courts over title disputes; and the RCT over matters relating to conservation and waste. *See, e.g.*,

[25] Final Order (Pet. App. Vol. 3 at E-1 to E-34).

Amarillo Oil Co. v. Energy-Agri Products, Inc., 1989 Westlaw 19057, No. C-6649 (Tex. March 8, 1989). FERC and the Texas courts acted adjudicatively and retrospectively, while the RCT in its Panhandle Field rulemaking proceeding acted legislatively and prospectively. Not surprisingly, and contrary to the RCT's contentions, the decisions of all these forums are entirely consistent and harmonious, particularly with regard to issues such as the definition of casinghead gas and the RCT's historical regulation of the Panhandle Field as separate oil and gas fields divided vertically at the gas-oil contact.[26]

The RCT also fails to state that in its recent Panhandle Field hearings its own examiners acknowledged FERC's findings and conclusions in Opinion No. 239 but did not even suggest that there was any conflict between FERC's decision and their own. In describing the scope of the FERC proceeding, the examiners stated: "Of primary concern [to FERC] were the alleged violations of the NGPA § 104, which effects a ceiling price (§ 104) for gas dedicated to interstate commerce . . . ."[27] Neither the examiners in their proposed decision nor the RCT in its Final Order makes any mention of what the RCT now characterizes as "two inconsistent regulatory schemes," "misinterpretation" and "misapplication" of Texas law, or "preemption" of the state's "examination and resolution" of important state regulatory issues. RCT at 19-20. Presumably, had those matters been a legitimate concern to the RCT, that agency would have addressed them in its Panhandle Field Final Order.

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[26] The court of appeals discussed these several decisions in detail. 874 F.2d at 1333; *see also Amarillo Oil Co. v. Energy-Agri Products, Inc.*, slip op. at 12; *Dorchester Gas Producing Co. v. Harlow Corp.*, 743 S.W.2d at 250-251; Final Order Findings of Fact 6, 7, 22, 23, and 24; Conclusions of Law 5, 6, 7, and 8; and Oil Field Rules, Rule 1 (Pet. App. Vol. 3 at E-3 to E-14).

[27] RCT Oil and Gas Docket No. 10-87,017, Proposal for Decision at 14 (App. at 72a, 94a-96a). The RCT's Final Order adopted and affirmed the examiners' proposal with slight modification.

The only purported example of inconsistency between FERC's Opinion No. 239 and the RCT's Final Order is cited at page 18 of the RCT's petition. There, the RCT states:

> The FERC approach and the Texas approach to regulation of production from the Panhandle fields are not harmonious. In Opinion No. 239, FERC has made a rigid determination that each operator must identify the point of gas-oil contact in his wellbore and that casinghead gas is only that gas produced from below such point. Under FERC's approach a well having a gas-oil ratio exceeding 4146 cubic feet of gas per barrel of oil (4146:1) is improperly completed above the gas-oil contact and is taking gas that does not qualify as casinghead gas. 44 FERC ¶ 61,128 at 61,355 (1985). FERC's arbitrary determination is based on FERC's conclusion that gas-oil ratios above 4146:1 indicate improper production from a dry gas horizon.

What the RCT does not say, and what is misleading about the quoted paragraph, is that the RCT's citation is not to Opinion No. 239. Rather, it is to the Commission's Phase 2 order, which was not before the court of appeals and which is not before this Court. There is no mention anywhere in Opinion No. 239 of a gas-oil ratio of 4146 cubic feet per barrel or of any other FERC-imposed "absolute and fixed standard" or "production constraint" as alleged by the RCT.

Furthermore, even if FERC's Phase 2 order is taken into account here, the RCT has completely misrepresented the nature of the evidence utilized by FERC in its Phase 2 proceedings.[28] FERC's task in Phase 2 was to quantify how much of the gas sold by the oil operators was casinghead gas and how much was not. In Opinion No. 307, *Stowers Oil & Gas Co.*, 44 FERC (CCH) ¶ 61,128 (1988), FERC adopted the methodology of the expert witness sponsored by the Enforcement Staff,

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[28] The RCT did not participate in Phase 2.

Northern, and Dorchester. He analyzed the casinghead gas production of hundreds of oil leases and wells adjacent or in proximity to the oil operators' leases. He then calculated the cumulative gas-oil ratio of these leases, *i.e.*, the total volume of casinghead gas produced from these leases over their entire lives in relation to the total amount of crude oil produced over the same period. The result was 4146 cubic feet of casinghead gas per barrel of crude oil. This number then was used to quantify the oil operators' casinghead gas production over the lives of their leases (typically from about 1980 through 1985). The 4146 cubic feet per barrel figure was not used by FERC as an instantaneous or producing gas-oil ratio to indicate compliance with field rules (as is the 5000 to 1 ratio cited by the RCT), nor was it used as any sort of FERC-imposed future production standard. It was nothing more than a tool utilized by a witness to arrive at his expert conclusion in the context of an evidentiary proceeding.

The RCT's comparison of the methodology approved by FERC in its Phase 2 proceedings to the presumptions set forth in its own Final Order is meaningless. The presumptions cited by the RCT (RCT at 19) are just that, rebuttable presumptions, prospective only, and indicating presumed compliance with the RCT's revised field rules. *See* Final Order, Appendix 1 (Pet. App. Vol. 3 at E-29 and 30). The field rules, however, remain clear:

> Panhandle Field oil wells are restricted to completion in horizons bearing producible oil. . . . No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only.

Final Order, Oil Field Rules, Rule 1 (Pet. App. Vol. 3 at E-14).[29] There is absolutely no inconsistency between

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[29] This is a restatement of existing law, not a revision of the field rules. *See, e.g.*, Final Order, Findings of Fact 24 and Conclusions of Law 5. (Pet. App. at Vol. 3 at E-8 and E-12).

these rules and FERC's findings, either in Phase 1 or Phase 2.[30]

The RCT cannot create a conflict where none exists by simply saying it is so. The best and only reliable expression of Texas law is that expressed by the Texas statutes, rules, and regulations; the decisions of the RCT; and the decisions of the Texas courts, all of which are consistent with FERC's actions below. Moreover, the RCT, despite its complaints here, proceeded unencumbered to reconsider and revise its own rules and has placed those rules into effect without incident or hindrance from FERC.

IV. Petitioners' criticism of FERC's findings regarding NGPA § 103 do not create a reviewable issue.

Petitioners also claim that FERC's findings regarding the scope of the oil operators' NGPA § 103 well category determinations intruded on the state's authority to define NGPA proration units and circumvented the procedures of NGPA § 503, 15 U.S.C. § 3413 (App. at 31a). Petitioners obviously disagree with the court of appeals' conclusion that FERC acted properly in examining the scope of the oil operators' § 103 determinations, but disagreement with a lower court's decision, without more, is not a sufficient reason for certiorari review.

NGPA § 103 establishes the ceiling price for "new, onshore production wells." A new, onshore production well is defined as any well (1) the surface drilling of which began on or after February 19, 1977, (2) which statisfies applicable well-spacing rules, and (3) which is not within an existing proration unit. "Proration unit" is defined under NGPA § 2(8) as that portion of a reservoir that the jurisdictional agency (here, the RCT) determines can be effectively and efficiently drained by

[30] Significantly, no oil operator has argued that it is presumptively in compliance with the RCT's field rules according to the presumptions set forth in the RCT Final Order and that, as a result, FERC's decision must conflict with the RCT Final Order.

a single well, 15 U.S.C. § 3301(8) (App. at 14), *i.e.*, one proration unit, one well.[31]

FERC strictly adhered to this statutory scheme. FERC found that the oil operators had obtained from the RCT valid, administratively final, § 103 well category determinations. Those determinations, however, covered only casinghead gas. They did not cover gas other than casinghead gas—the same gas that would otherwise be produced by Dorchester from the proration units assigned to its gas wells. FERC further found that under existing state statutes and regulations these oil and gas proration units are separated vertically at the gas-oil contact. Thus, FERC gave full effect under the NGPA to the state's longstanding practice of separately prorating the Panhandle gas and oil fields. Final Order, Findings of Fact 6, 7, and 22 (Pet. App. Vol. 3 at E-3 and E-8).

Petitioners contend that FERC's findings regarding the scope of the oil operators' § 103 determinations constitute an unlawful circumvention of the reopening procedures established under NGPA § 503(d), 15 U.S.C. § 3413(d) (App. at 35a). Petitioners further assert that until the oil operators' determinations are reopened and vacated, FERC has no jurisdiction over the oil operators' gas sales by virtue of NGPA § 601(a)(1)(B)(iii), 15 U.S.C. § 3431(a)(1)(B)(iii) (App. at 44a).

FERC did not seek to reopen the oil operators' NGPA § 103 well category determinations, as no purpose would have been served by doing so. The oil operators obtained

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[31] The RCT is wrong in asserting that a proration unit is just the surface acreage assigned to a well. Under the NGPA, a proration unit relates to a subsurface accumulation of natural gas—a portion of a reservoir. *See also* NGPA § 2(6) for the definition of "reservoir." 15 U.S.C. § 3301(6) (App. at 14a). The RCT recognizes this fact in its Final Order: "Production of unnecessary upper gas interval gas through Panhandle Field oil wells drains reserves which properly lie within the assigned proration units of West and East Panhandle gas wells." Final Order Findings of Fact 20 (Pet. App. Vol. 3 at E-7).

valid NGPA § 103 well category determinations for sales of casinghead gas, and their sales of casinghead gas at NGPA § 103 prices were not unlawful under § 504 of the NGPA. FERC had no reason, therefore, to reopen those determinations. However, the oil operators did not obtain any well category determinations for their sales of gas other than casinghead gas; for such sales, there were no determinations to reopen.[32]

Petitioners' arguments are premised on an incorrect "all-or-nothing" view of NGPA § 103. Well category determinations are completion location specific, not well specific. As the Fifth Circuit has observed:

> When Congress was concerned with depth of production, completion location was a proper focus since it is a point of production from the well bore.
>
> * * * *
>
> That a well may produce gas that qualifies under two different pricing provisions is a result of the limited use of completion location as the qualifying unit of production in sections 102 and 103.

Ecee Inc. v. FERC, 645 F.2d 339, 355-56 (5th Cir. 1981). Further, FERC's rules specifically provide that if a producer obtains a NGPA § 103 well category determination but completes the well in a second proration unit not considered in the prior determination, the prior determination does not serve to qualify gas produced from the second proration unit for NGPA § 103 pricing. *Clarification of Regulations Regarding New, Onshore Production Wells*, Order No. 149, FERC Stats. and Regs. (CCH) ¶ 30,257 at 31,571 (1977-81); 46 F.R. 29697 (June 3, 1981); 46 F.R. 32237 (June 22, 1981).

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[32] For regulatory purposes the Panhandle Field is not classified by the RCT as a single field but divided into separate oil and gas fields. *See* Final Order Findings of Fact 6 and 7 (Pet. App. Vol. 3 at E-3 to E-4). The oil operators obtained their NGPA § 103 classifications for casinghead gas produced from the Panhandle Oil Field, not from the Panhandle Gas Field.

Thus, FERC was on sound footing in not reopening and vacating any of the oil operators' NGPA § 103 well category determinations. FERC gave full effect to these determinations and was not obligated to proceed in this case under NGPA § 503. Likewise, because only the oil operators' sales of casinghead gas were subject to NGPA § 103, only these sales were removed from FERC's NGA jurisdiction under NGPA § 601(a)(1)(B). FERC properly exercised its continuing NGA jurisdiction over the oil operators' sales of gas other than casinghead gas, *i.e.*, their sales of old gas previously dedicated to interstate commerce.

V. The oil operators' retroactive penalty argument is not properly subject to review by this Court.

The oil operators contend that FERC's findings below impose a retroactive penalty upon them. Oil Operators at 17-18. However, the FERC orders affirmed by the court of appeals in this case dealt only with the question of whether violations occurred. FERC found that the oil operators violated federal law and ordered them to cease those violations. The question of appropriate remedies was left for Phase 2. As noted previously, FERC only recently completed Phase 2, and its Phase 2 orders were not reviewed by the court of appeals in *Walker Operating Corp. v. FERC*. Accordingly, the oil operators' retroactive penalty arguments should be dismissed as unreviewable.

VI. The proceedings below were fair; the oil operators' due process rights were not violated.

The oil operators claim that they were denied their due process rights because the show cause order and Enforcement Staff's direct evidence assertedly did not disclose the Staff's theory of the case. Oil Operators at 18. The court of appeals summarily disposed of this argument, and the oil operators fail to demonstrate that the court erred or why this Court should review the merits of their argument.

The oil operators are incorrect in their characterization of FERC's show cause order and the evidentiary proceedings before the presiding ALJ. The oil operators take an overly restrictive view of what a show cause order must contain; in essence, they argue that it must provide the very exactitude that the subsequent hearing was supposed to provide. However, the show cause order was only a preliminary step commencing a lengthy administrative proceeding. All that is necessary of such an order is that the oil operators have sufficient and adequate notice of the nature of the proceeding.

There can be no question that the oil operators had ample notice of the issues to be adjudicated in the FERC proceeding and the nature of the violations of federal law they were alleged to have committed. The oil operators can claim neither surprise nor prejudice in connection with the evidence adduced at the hearing. They cannot point to any direct evidence which does not directly relate to the allegations in the show cause order. They cannot point to any rebuttal evidence which does not directly relate to matters and defenses raised in the direct testimony of their own witnesses. They had the opportunity to confront each witness sponsored by their opponents and utilized every such opportunity to advance their theory of the case. Indeed, as the record unequivocally shows, the ALJ afforded them tremendous latitude in presenting their defense in the manner in which they saw fit.

The oil operators now say that they apparently misread the show cause order. They say the order alleged that the brown dolomite formation is not productive of oil anywhere in the entire field. This reading of the order purportedly led them astray in selecting witnesses and presenting their case. Oil Operators at 18-19. Contrary to the oil operators' claim, however, the show cause order said no such thing. Paragraph 29 of the order stated:

> The brown dolomite stratum is productive only of dry gas at the level at which the operators of each

of the oil wells identified in Appendix A have perforated or have caused the performation of such oil wells.

Stowers Oil & Gas Co., 26 FERC (CCH) ¶ 61,207 at 61,478 (App. at 56a). This is precisely what the direct testimony of the Staff demonstrated. That the oil operators chose to ignore this very clear language and pursued a different theory of the case cannot reasonably be said to be an error on FERC's part.

Nor is it accurate for the oil operators to contend that they were surprised by a "new theory" that Staff made at the eleventh hour. Oil Operators at 19. Neither the Staff witnesses' testimony regarding oil production nor the particular testimony the oil operators now most strenuously complain of—that of the Railroad Commission's ex-Chief Director, Mr. Harris—propounded any new theories. Rather, that evidence properly rebutted the oil well operators' arguments that all of their gas was casinghead gas under Texas law. What Staff demonstrated was that the oil well operators' witnesses were wrong in their views of how the field was divided into gas and oil proration units and wrong in their claim that oil found anywhere in the Panhandle Field's brown dolomite formation made all of their gas casinghead gas entitled to NGPA incentive prices. This is exactly what rebuttal evidence is supposed to do, and the ALJ's decision not to permit surrebuttal testimony did not violate any due process requirements.

The oil operators couch their claim in due process terms, but in essence it is little more than a complaint about the nature of some of the rebuttal evidence in an investigatory proceeding. The trier of fact in such proceedings normally is accorded wide latitude in resolving evidentiary disputes and rarely does the resolution of those disputes engender a question worthy of review by this Court. *See, e.g., Universal Camera Corp. v. NLRB*, 340 U.S. 474, 488 (1951); *Consolo v. Federal Maritime Commission*, 383 U.S. 607, 619-20 (1966). It certainly

does not do so here. The court of appeals ruled on oil operators' contention and they do not point to any unusual circumstance or conflict which merits further review.

CONCLUSION

For the foregoing reasons, the petitions for writ of certiorari should be denied.

Respectfully submitted,

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October 14, 1989

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IN THE

Supreme Court of the United States

OCTOBER TERM, 1989

RAILROAD COMMISSION OF TEXAS,
Petitioner,
v.

FEDERAL ENERGY REGULATORY COMMISSION, *et al.*,
Respondents.

WALKER OPERATING CORPORATION, *et al.*,
Petitioners,
v.

FEDERAL ENERGY REGULATORY COMMISSION, *et al.*,
Respondents.

On Petition for a Writ of Certiorari to the United States Court of Appeals for the Tenth Circuit

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APPENDIX TO BRIEF IN OPPOSITION OF RESPONDENTS DORCHESTER MASTER LIMITED PARTNERSHIP, NATURAL GAS PIPELINE COMPANY OF AMERICA, AND NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

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APPENDIX TABLE OF CONTENTS

APPENDIX A

RULE 28.1 LISTINGS

DORCHESTER MASTER LIMITED PARTNERSHIP

Dorchester Master Limited Partnership is the successor in interest to Dorchester Gas Producing Company, a party to the proceedings before the Federal Energy Regulatory Commission. Dorchester Master Limited Partnership has no subsidiaries or affiliates. Damson Oil Corporation is the general partner of Dorchester Master Limited Partnership.

NATURAL GAS PIPELINE COMPANY OF AMERICA

Natural Gas Pipeline Company of America is a subsidiary of MidCon Corp., 701 East 22nd Street, Lombard, Illinois, 60148, which, in turn, is a wholly-owned subsidiary of Occidental Petroleum Corporation, 10889 Wilshire Boulevard, Los Angeles, California, 90024.

Occidental Petroleum Corporation direct or indirect subsidiaries that are owned less than one hundred percent are:

Church & Dwight Co., Inc.
Energy America Incorporated
IBP, Inc.
Rail to Water Transfer Corporation
Primex Ltd.
Carbocloro S.A. Industrial Quimicas
Sanital Comercio e Empreendimentos Ltda.
Ftaliquimica S.A.
Oxypar Industries Quimicas S.A.
Malharia Industrial do Nordeste S.A.
Vinor Vinilicos do Nordeste Ltda.
Industrias Oxy S.A. de C.V.
Sumitomo Durez Co. Ltd.
Diamond Shamrock Chemicals Company Pty. Limited
Canadian Occidental Petroleum Ltd.
Fertilizer Belgium S.A.
International Ore and Fertilizer S.p.A.
Industria Quimica de Portugesa, S.A.

Mississippi Chemical Corporation
Tororo Industrial Chemicals and Fertilizers, Ltd.
Occidental Chemical China, Ltd.
Occidental Far East Limited
Occidental Chemical Chile, S.A.I.
Occidental Chemical New Zealand Limited
Thai Occidental Chemical Ltd.
Thai Diamond Shamrock Ltd.
Trans-Jeff Chemical Corporation
Oxy Metal Industries (France) S.A.
OXYTECH Systems, Inc.
Island Creek of China Coal, Ltd.
O-K Investment Company, Ltd.
Minera Azteca, S.A. de C.V.
Occidental Minerals (Philippines), Inc.
C-D Development Corporation
Newco Holding Corporation
Citco Amazonas Petroléo Ltda
Citco Barreirinhas Petroleo do Brasil Ltda
Citco Rio Petroleo Ltda
Petroleo de Brasil Ltda
East Texas Salt Water Disposal Company
Dixie Pipeline Company
Occidental of Aruba, Inc.
602 Operating Corporation
Oil Casualty Insurance, Ltd.
Oil Insurance Limited
Hispano Inversion, S.A.
Occidental de Espana, S.A.
Petway Products Distributors, Inc.
Hybrid Rice, Inc.
RAMM Hybrids International, Inc.
RAMM Hybrids, Inc.
Carter Day Industries, Inc.
Eko Hotels, Ltd.
Natural Gas Pipeline Company of America
Hazox Alternate Energy, Inc.
Hazox Corporation
Kildeer Area Development Corporation

NORTHERN NATURAL GAS COMPANY, DIVISION OF ENRON CORP.

Northern Natural Gas Company is a division of Enron Corp. Subsidiaries, affiliates, and divisions of Enron Corp. are:

Ajax Corporation (Massachusetts)
    The Apollo Group, Inc. (Massachusetts)
Belco Petroleum Corporation (Delaware)
    Belco Petroleum International, Ltd. (Delaware)
        Belco Petroleum Latin America, S.A. (Delaware)
            Belco Petroleum Corporation of Peru (Delaware)
    Belco Petroleum of Israel, Ltd. (Delaware)
        Sonneborn Associates Petroleum Corporation (Delaware)
    Belcoal Inc. (Delaware)
Enron Americas, Inc. (Delaware)
    Enron Peru, Inc. (Delaware
Enron Arctic Gas Company (Delaware)
Enron Art Foundation (Nebraska)
Enron Capital Corp. (Delaware)
Enron Coal Company (Delaware)
Enron Coal Pipeline Company (Delaware)
Enron Data Processing Company (Texas)
Enron Foundation—Houston (Texas)
Enron Foundation—Omaha (Nebraska)
Enron Gas Gathering, Inc. (Delaware)
    Enron Natural Gas Gathering Co. (Texas)
Enron Gas Marketing, Inc. (Delaware)
Enron Gas Processing Company (Delaware)
Enron Gas Production Company (Texas)
Enron Gas Services Company (Delaware)
Enron Gas Supply Company (Delaware)
Enron Gas Transportation Company (Delaware)
Enron Helium Company (Delaware)
Enron Holdings, Inc. (Delaware)
Enron International Incorporation (Delaware)

Enron Gas Liquids International (U.K.), Ltd.
Enron Gas Liquids France S.A.R.L. (France) (Formerly NLFI France S.A.R.L.)
NLFI (Far East) Trading Private Limited (Singapore) (To Be Dissolved)
IPI Orient Ltd. (Hong Kong) (To Be Dissolved)
Enron Oil Corp. (Delaware)
Enron Oil Ltd. (Partnership) (London)
Enron Oil PTE Ltd. (Singapore)
The Protane Corporation
Citadel Corporation Limited (Cayman Island)
Citadel Venezolana S.A. (Venezuela)
Industrial Gases Limited (Jamaica)
Manufacturera de Aparatos Domesticos, S.A. (Madosa) Venezuela
Industrias Ventane, S.A. (Venezuela)
Industrial Lacarda, S.A. (Venezuela)
Servicios Consolidados Ventane, S.A. (Venezuela)
Servicios Vengas, S.A. (Venezuela)
Transporte Mil Ruedas, S.A. (Venezuela)
Vengas de Caracas (Venezuela)
Vengas del Centro, S.A. (Venezuela)
Vengas de Occidente, S.A. (Venezuela)
Vengas de Oriente, S.A. (Venezuela)
ProCaribe, Inc. (Puerto Rico)
ProCaribe Division of The Protane Corporation
Progasco, Inc. (Puerto Rico)
Enron Gas Liquids, Inc. (Delaware)
Weddell Corporation (Liberia)
Enron Liquids Pipeline Company (Delaware)
Enron Minerals Company (Delaware)
Enron Mobile Bay, Inc. (Texas)
Enron NGL Corp. (Delaware)

Enron Oil & Gas Company (Delaware)
Enron Exploration Company (Texas)
Enron Oil Egypt Inc. (Texas)
Enron Oil Syria Inc. (Texas)
Enron Oil & Gas Marketing, Inc. (Texas)
Enron Oil Malaysia Inc.
IN Holdings, Inc. (Delaware)
Enron Oil Canada, Ltd. (Alberta, Canada)
Enron Oil Trading & Transportation Company (Delaware)
Enron Oil Pipeline Company (A Division)
Enron Oil Trading & Transportation Canada Ltd. (Canada)
Webster Transportation Company, Inc. (Louisiana)
Enron Overthrust Pipeline Company (Delaware)
Enron Power Corp.
Enron Power Enterprise Corp.
Enron Trailblazer Pipeline Company (Delaware)
Houston Pipe Line Company (Texas)
The Bermuda Company (Texas)
Gulf Company Ltd. (Bermuda)
Black Marlin Pipeline Company (Texas)
Coal Properties Corporation (Illinois)
Comanche Marketing, Inc. (Texas)
Cora Dock Corporation (Texas)
Enron Clearing House Company (Texas)
Enron Co-Gen Fuels Company (Texas)
Enron Gas Pipeline Operating Company
Enron Industrial Natural Gas Company (Texas)
Enron Interstate Pipeline Company (Delaware)
Enron Mojave, Inc. (Texas)
Enron Texoma Gas Company (Texas)
HNG Capital Corp. (Delaware)
HNG Holdings Corp. (Texas)
IDT Gas Supply Company (Texas)
Katy-Waha Gas Marketing Company (Texas)

Intratex Gas Company (Texas)
Natural Gas Marketing & Storage Company (Texas)
Pacific Atlantic Marketing, Inc. (Texas)
Panhandle Gas Company (Texas)
Pott Industries Inc. (Missouri)
Marcoal Inc. (W. Virginia)
Riverside Farms Company (Illinois)
Transgulf Pipeline Company (Florida)
Transwestern Pipeline Company (Delaware)
Valley Pipe Lines, Inc. (Texas)
Valley Pipe Lines Offshore Division (Assumed Name)
Webb-Duval Pipeline, Inc. (Delaware)
KMC Associates, Incorporated (Colorado)
NGP Pipeline Company (Delaware)
Northern Intrastate Pipeline Company (Delaware)
Northern Natural Gas Supply Company (Delaware)
Northern Plains Natural Gas Company (Delaware)
AmNorth, Inc. (Nebraska)
Pathfinder Assurance Limited (Bermuda)

Divisions of Enron Corp.:

Enron EOR Services Company
Enron International Developmental Division
Gas Pipeline Group Division
Information Management Division
Northern Natural Gas Company Division
San Juan Gas Company Division

Joint Venture Companies:

Citrus Corp. (Delaware)
Owned by Sonat—50% (Class A Stock)
Houston Pipe Line—50% (Class B Stock)
Citrus Interstate Pipeline Company (Delaware)
Citrus Industrial Sales Company, Inc. (Delaware)

Citrus Marketing, Inc. (Florida)
Citrus Trading Corp. (Delaware)
Florida Gas Transmission Company (Delaware)

Enron/Dominion Cogen Corp. (Delaware)
Owned by Enron—50%
Dominion Resources—50%
Cogenron Inc. (Delaware)
(EC1C owns 100% of common; Outside Investors own 100% of preferred stock)
Enron Bayou Co-Gen, Inc. (Texas)
Enron Cogeneration One Company (Delaware)
Enron Cogeneration Two Company (Delaware)
Enron Cogeneration Three Company (Delaware)
Enron Cogeneration Four Company (Delaware)
Enron Cogeneration Five Company (Delaware)
Enron Cogeneration Resources Company (Delaware)
Enron Cogeneration Six Company (Delaware)

Enron NGL Processing Limited Partnership (Delaware)

HT Gathering Company (Texas)
Class A Voting Common Stock—50/50 Tenngasco and Houston Pipe Line
Class B Common Stock—100% Houston Pipe Line

Jubilee Pipeline Company (Texas)
An Unincorporated Joint Venture among:
Oklahoma Gas Pipeline Company—35%
Enron Mobile Bay, Inc.—22.5%
Tabasco Gas Pipe Line Company—15%
Sonat Mobile Bay Inc.—12.5%
Odeco Gas Gathering Inc.—7.5%
Murphy Gas Gathering Inc.—7.5%

Mojave Pipeline Operating Company (Texas)
Owned by Mojave Pipeline Company, a Partnership composed of:
Enron Mojave, Inc.—50% and
El Paso Mojave—50%

Norelf Limited (Bermuda)
Owned by Enron Gas Liquids Inc.—42.5%
Corelf—42.5%
Gazocean (Bermuda) Trading Ltd.—15%

Northern Border Pipeline Company (Texas)
Owned by Northern Plains Natural Gas Company—22.75%
Pan Border Gas Company—22.75%
TransCanada Border PipeLine Ltd.—30%
United Mid-Continent Pipeline Company—12.25%
Norwest Border Pipeline Company—12.25%

Oasis Pipe Line Company (Delaware)
Owned by Houston Pipe Line Company
The Dow Chemical Company and
Tenngasco Gas Supply Company

San Marco Pipeline Company (Colorado)
Owned by Houston Pipe Line Company—50%
The Denver & Rio Grande Western Railroad Co.—50%

Seagull Shoreline System (A Texas Partnership composed of Northern Intrastate Pipeline Company, Texas Eastern Offshore Company and Seagull Transmission Company)

The Standard Shale Products Company (Colorado)
Owned by Conoco—70%
Houston Pipe Line Company—30%

Zapata Gulf Marine Corporation (Delaware)
Owned by Houston Pipe Line Company—360 shares—Class A
Zapata Corporation—426 shares—Class B
Halliburton Company—214 shares—Class C

APPENDIX B

NATURAL GAS ACT 15 U.S.C. §§ 717 *et seq.*

§ 717. Necessity for regulation of natural gas companies

(a) As disclosed in reports of the Federal Trade Commission made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.

(b) The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

(c) The provisions of this chapter shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State commission. The matters exempted from the provisions of this chapter by this subsection are declared to be matters primarily

of local concern and subject to regulation by the several States. A certificaiton from such State commission to the Federal Power Commission that such State commission has regulatory jurisdiction over rates and service of such person and facilities and is exercising such jurisdiction shall constitute conclusive evidence of such regulatory power or jurisdiction.

June 21, 1938, c. 556, § 1, 52 Stat. 821; Mar. 27, 1954, c. 115, 68 Stat. 36.

§ 717f. Construction, extension, or abandonment of facilities; certificate of convenience and necessity; condemnation proceedings

(a) Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: *Provided,* That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing,

and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilties therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: *Provided, however,* That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: *Provided, however,* That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service

or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(d) Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Except in the cases governed by the provisos contained in subsection (c) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization.

(g) Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

(h) When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the propery is situated: *Provided*, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds $3,000.

June 21, 1938, c. 556, § 7, 52 Stat. 824; Feb. 7, 1942, c. 49, 56 Stat. 83; July 25, 1947, c. 333, 61 Stat. 459.

APPENDIX C

NATURAL GAS POLICY ACT OF 1978
15 U.S.C. §§ 3301 *et seq.*

§ 3301. Definitions

For purposes of this chapter—

* * * *

(6) Reservoir.—The term "reservoir" means any producible natural accumulation of natural gas, crude oil, or both, confined—

(A) by impermeable rock or water barriers and characterized by a single natural pressure system; or

(B) by lithologic or structural barriers which prevent pressure communication.

* * * *

(8) Proration unit.—The term "proration unit" means—

(A) any portion of a reservoir, as designated by the State or Federal agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well;

(B) any drilling unit, production unit, or comparable arrangement, designated or recognized by the State or Federal agency having jurisdiction with respect to production from the reservoir, to describe that portion of such reservoir which will be effectively and efficiently drained by a single well; or

(C) if such portion of a reservoir, unit, or comparable arrangement is not specifically provided for by State law or by any action of any State or Federal agency having regulatory jurisdiction with respect to production from such

reservoir, any voluntary unit agreement or other comparable arrangement applied, under local custom or practice within the locale in which such reservoir is situated, for the purpose of describing the portion of a reservoir which may be effectively and efficiently drained by a single well.

* * * *

(18) Committed or dedicated to interstate commerce.—

(A) General rule—The term "committed or dedicated to interstate commerce", when used with respect to natural gas, means—

(i) natural gas which is from the Outer Continental Shelf; and

(ii) natural gas which, if sold, would be required to be sold in interstate commerce (within the meaning of the Natural Gas Act) under the terms of any contract, any certificate under the Natural Gas Act, or any provision of such Act.

(B) Exclusion.—Such term does not apply with respect to—

(i) natural gas sold in interstate commerce (within the meaning of the Natural Gas Act)—

(I) under section 6 of the Emergency Natural Gas Act of 1977;

(II) under any limited term certificate, granted pursuant to section 7 of the Natural Gas Act, which contains a pregrant of abandonment of service for such natural gas;

(III) under any emergency regulation under the second proviso of section 7(c) of the Natural Gas Act; or

(IV) to the user by the producer and transported under any certificate, granted pursuant to section 7(c) of the Natural Gas Act, if such certificate was specifically granted for the transportation of that natural gas for such user;

(ii) natural gas for which abandonment of service was granted before November 9, 1978, under section 7 of the Natural Gas Act; and

(iii) natural gas which but for this clause, would be committed or dedicated to interstate commerce under subparagraph (A)(ii) by reason of the action of any person (including any successor in interest thereof, other than by means of any reversion of a leasehold interest), if on May 31, 1978—

(I) neither that person, nor any affiliate thereof, had any right to explore for, develop, produce, or sell such natural gas; and

(II) such natural gas was not being sold in interstate commerce (within the meaning of the Natural Gas Act) for resale (other than any sale described in clause (i)(I), (II), or (III)).

* * * *

(21) First Sale.—

(A) General rule.—The term "first sale" means any sale of any volume of natural gas—

(i) to any interstate pipeline or intrastate pipeline;

(ii) to any local distribuiton company;

(iii) to any person for use by such person;

(iv) which precedes any sale described in clauses (i), (ii), or (iii); and

(v) which precedes or follows any sale described in clauses (i), (ii), (iii), or (iv) and is defined by the Commission as a first sales in order to prevent circumvention of any maximum lawful price established under this chapter.

(B) Certain sales not included.—Clauses (i), (ii), (iii), or (iv) of subparagraph (A) shall not include the sale of any volume of natural gas by any interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof, unless such sale is attributable to volumes of natural gas produced by such interstate pipeline, intrastate pipeline, or local distribution company, or any affiliate thereof.

* * * *

SUBCHAPTER A—WELLHEAD PRICING

PART A—WELLHEAD PRICE CONTROLS

§ 3312. Ceiling price for new natural gas and certain natural gas produced from Outer Continental Shelf

(a) Application.—The maximum lawful price computed under subsection (b) of this section shall apply to any first sale of natural gas delivered during any month in the case of—

(1) new natural gas; and

(2) natural gas produced from any old lease on the Outer Continental Shelf and qualifying under subsection (d) of this section for the new natural gas ceiling price.

(b) Maximum lawful price.—The maximum lawful price under this section for any month shall be—

(1) \$1.75 per million Btu's, in the case of April 1977; and

(2) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subsection for the preceding month multiplied by the monthly equivalent of a factor equal to the sum of—

(A) the annual inflation adjustment factor applicable for such month; plus

(B) (i) .035, in the case of any month beginning before April 20, 1981; or

(ii) .04, in the case of any month beginning after April 20, 1981.

(c) Definition of new natural gas.—

(1) General rule.—For the purposes of this section, the term "new natural gas" means each of the following categories of natural gas:

(A) New OCS leases.—Natural gas determined in accordance with section 3413 of this title to be produced from a new lease on the Outer Continental Shelf.

(B) New onshore wells.—Natural gas determined in accordance with section 3413 of this title to be produced (other than from the Outer Continental Shelf) from—

(i) any new well which is 2.5 miles or more (determined in accordance with paragraph (2)) from the nearest marker well;

or

(ii) any completion location, of any new well, which is located at a depth at least 1,000 feet below the deepest completion location of each marker well within 2.5 miles (determined in accordance with paragraph (2)) of such new well.

(C) New onshore reservoirs.—

(i) General rule.—Except as provided in clauses (ii) and (iii), natural gas determined in accordance with section 3413 of this title to be produced (other than from the Outer Continental Shelf) from a reservoir from which natural gas was not produced in commercial quantities before April 20, 1977.

(ii) Behind-the-pipe exclusion.—Clause (i) shall not apply to natural gas produced from any reservoir if—

(I) the reservoir was penetrated before April 20, 1977, by an old well from which natural gas or crude oil was produced in commercial quantities (whether or not such production was from such reservoir); and

(II) natural gas could be been produced in commercial quantities from such reservoir through such old well before April 20, 1977.

(iii) Withheld gas exclusion.—Clause (i) shall not apply to natural gas produced from any reservoir—

(I) if such natural gas is produced through an old well; and

(II) subject to clause (iv), suitable facilities for the production and deliv-

ery to a pipeline of such natural gas were in existence on April 20, 1977.

(iv) Emergency sale facilities.—The criteria of clause (iii) (II) shall not be considered to be met by reason of the existence of production and delivery facilities which were installed to carry out sales and deliveries of natural gas—

(I) under section 6 of the Emergency Natural Gas Act of 1977; or

(II) under the emergency sale authority pursuant to Opinion 699-B issued by the Federal Power Commission under section 7(c) of the Natural Gas Act.

(2) Determinations of distance.—For purposes of determining the distance from any new well to any marker well—

(A) Surface location to surface location.—The measurement shall be the horizontal distance from the surface location of the new well to the surface location of the marker well—

(i) in any case in which the new well meets requirements for the nondirectional drilling of wells prescribed by the appropriate State or Federal agency having regulatory jurisdiction over the drilling of such well; or

(ii) in any case in which—

(I) the surface drilling of such new well began on or after February 19, 1977;

(II) production of natural gas in commercial quantities began from such well before November 9, 1978; and

(III) the drilling of such well was not subject to any requirement regarding directional or nondirectional drilling, or the drilling of such well was subject to requirements regarding directional drilling but such requirement did not necessitate the obtaining of any permit or other certificate before drilling began.

(B) Completion location to surface location. —In the case of any new well which is not covered by subparagraph (A), the measurements shall be the horizontal distance from—

(i) the closest point of any completion location of the new well, vertically projected to the same elevation as the surface location of the nearest marker well; to

(ii) the surface location of such marker well.

(3) Determination of commercial quantities.— For purposes of determining whether production of natural gas has occurred in commercial quantities under paragraph (1) (C)—

(A) a rebuttable presumption exists that production from a reservoir in commercial quantities has not occurred if natural gas has not been sold and delivered from such reservoir before April 20, 1977; and

(B) quantities of natural gas sold in interstate commerce (within the meaning of the Natural Gas Act) shall not be taken into account if such quantities were sold before November 9, 1978—

(i) under section 6 of the Emergency Natural Gas Act of 1977; or

(ii) under the emergency sale authority pursuant to Opinion 699-B issued by the Federal Power Commission under section 7 (c) of the Natural Gas Act.

(4) New wells which are also marker wells.—For purposes of applying subsection (c) (1) (B) (ii) of this section in the case of any marker well which is also a new well under section 3301 (3) (B) of this title, the reference in such subsection (c) (1) (B) (ii) of this section to the deepest completion location of any marker well shall be deemed to be a reference to any subsurface location from which natural gas was produced in commercial quantities after January 1, 1970, and before February 19, 1977.

(d) OCS gas qualifying for new natural gas ceiling price.—For purposes of this section—

(1) OCS reservoirs discovered on or after July 27, 1976.—Natural gas determined in accordance with section 3413 of this title to be produced from an old lease on the Outer Continental Shelf shall qualify for the new natural gas ceiling price if such natural gas is produced from a reservoir which was not discovered before July 27, 1976.

(2) Reservoirs penetrated before July 27, 1976.—For purposes of paragraph (1), a reservoir shall be considered as having been discovered before July 27, 1976, if—

(A) such reservoir was penetrated by a well before July 27, 1976; and

(B) with respect to such well—

(i) the results of any production test meeting the requirements of OCS Order No. 4 demonstrate that, as of the time of such test, the reservoir is capable of producing in

paying quantities (within the meaning of such Order);

(ii) any production capability evidence meeting the requirements of OCS Order No. 4 demonstrates that, as of the time such evidence is obtained, the reservoir is capable of producing in paying quantities (within the meaning of such Order); or

(iii) subject to paragraph (3), an induction-electric log, sidewall cores and core analysis, or a wire line formation test indicates that, as of the time of such test, the reservoir is commercially producible.

(3) Effect of negative production capability tests.—For purposes of paragraph (1), a reservoir shall not be considered as having been discovered before July 27, 1976, by the penetration of such reservoir by a well before July 27, 1976, if, with respect to such well—

(A) a production test meeting the requirements of OCS Order No. 4 was performed and the results of such test fail to demonstrate that, as of the time of such test, such reservior [1] was capable of producing in paying quantities (within the meaning of such Order); and

(b) production capability evidence meeting the requirements of OCS Order No. 4 does not exist or, if existing, does not demonstrate that, as of the date such evidence was obtained, such reservoir was capable of producing in paying quantities (within the meaning of such Order).

(4) Burden of proof.—For purposes of paragraph (1), the producer shall have the burden of showing that—

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[1] So in original. Probably should be "reservoir".

(A) no test described in paragraph (2)(B)(i) or (iii) was performed and no evidence described in paragraph (2)(B)(ii) or (iii) exists; or

(B) if any such test was performed or such evidence exists, the results of such test or such evidence do not provide the applicable demonstration or indication specified under paragraph (2).

(5) Definition of OCS Order No. 4.—For purposes of this subsection, the term "OCS Order No. 4" means the order numbered 4 of the Conservation Division, Geological Survey, Department of the Interior, as approved by the Chief of the Conservation Division on August 28, 1969.

(e) Exclusion of certain Alaska natural gas.—The preceding provisions of this section shall not apply to any natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(Pub.L. 95-621, Title I, § 102, Nov. 9, 1978, 92 Stat. 3358.)

§ 3313. Ceiling price for new, onshore production wells

(a) Application.—In the case of natural gas determined in accordance with section 3413 of this title to be produced from any new, onshore production well, the maximum lawful price computed under subsection (b) of this section shall apply to any first sale of such natural gas delivered during any month.

(b) Maximum lawful price.—

(1) General rule.—The maximum lawful price under this section for any month shall be—

(A) $1.75 per million Btu's, in the case of April 1977; and

(B) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this paragraph for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor applicable for such month.

(2) Production after 1984 from wells 5,000 feet or less in depth.—Effective beginning with the month of January 1985 and in any month thereafter, in the case of any first sale of natural gas which was not committed or dedicated to interstate commerce on April 20, 1977, and which is produced from a new, onshore production well from a completion location located at a depth of 5,000 feet or less, the maximum lawful price under this section for any such natural gas delivered during any month shall be a price which is midway between—

(A) the maximum lawful price, per million Btu's, computed for such month under section 3312 of this title (relating to new natural gas); and

(B) the maximum lawful price, per million Btu's, computed for such month under paragraph (1).

(c) Definition of new, onshore production well.—For purposes of this section, the term "new, onshore production well" means any new well (other than a well located on the Outer Continental Shelf)—

(1) the surface drilling of which began on or after February 19, 1977;

(2) which satisfies applicable Federal or State well-spacing requirements, if any; and

(3) which is not within a proration unit—

(A) which was in existence at the time the surface drilling of such well began;

(B) which was applicable to the reservoir from which such natural gas is produced; and

(C) which applied to a well (i) which produced natural gas in commercial quantities or (ii) the surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

(d) Exclusion of certain Alaska natural gas.—The preceding provisions of this section shall not apply to any natural gas produced from the Prudhoe Bay Unit of Alaska and transported through the natural gas transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(Pub.L. 95-621, Title I, § 103, Nov. 9, 1978, 92 Stat. 3361.)

§ 3314. Ceiling price for sales of natural gas dedicated to interstate commerce

(a) Application.—In the case of natural gas committed or dedicated to interstate commerce on November 8, 1978, and for which a just and reasonable rate under the Natural Gas Act was in effect on such date for the first sale of such natural gas, the maximum lawful price computed under subsection (b) of this section shall apply to any first sale of such natural gas delivered during any month.

(b) Maximum lawful price.—

(1) General rule.—The maximum lawful price under this section for any month shall be the higher of—

(A) (i) the just and reasonable rate, per million Btu's, established by the Commission which was (or would have been) applicable to the first sale of such natural gas on April 20, 1977, in the case of April 1977; and

(ii) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subparagraph for the preceding month multiplied by the monthly equivalent of the annual inflation adjustment factor applicable for such month, or

(B) any just and reasonable rate which was established by the Commission after April 27, 1977, and before November 9, 1978, and which is applicable to such natural gas.

(2) Ceiling prices may be increased if just and reasonable.—The Commission may, by rule or order, prescribe a maximum lawful ceiling price, applicable to any first sale of any natural gas (or category thereof, as determined by the Commission) otherwise subject to the preceding provisions of this section, if such price is—

(A) higher than the maximum lawful price which would otherwise be applicable under such provisions; and

(B) just and reasonable within the meaning of the Natural Gas Act.

(Pub.L. 95-621, Title I, § 104, Nov. 9, 1978, 92 Stat. 3362.)

§ 3317. Ceiling price for high-cost natural gas

(a) Wells completed below 15,000 feet.—In the case of any first sale of high-cost natural gas produced from any well the surface drilling of which began on or after February 19, 1977, if such production from any comple-

tion location which is located at a depth of more than 15,000 feet, the maximum lawful price under this section for such natural gas delivered during any month shall be the maximum lawful price, per million Btu's, computed for such month under section 3312 of this title (relating to new natural gas).

(b) Commission authority to prescribe higher incentive prices.—The Commission may, by rule or order, prescribe a maximum lawful price, applicable to any first sale of any high-cost natural gas, which exceeds the otherwise applicable maximum lawful price to the extent that such special price is necessary to provide reasonable incentives for the production of such high-cost natural gas.

(c) Definition of high-cost natural gas.—For purposes of this section, the term "high-cost natural gas" means natural gas determined in accordance with section 3413 of this title to be—

(1) produced from any well the surface drilling of which began on or after February 19, 1977, if such production is from a completion location which is located at a depth of more than 15,000 feet;

(2) produced from geopressured brine;

(3) occluded natural gas produced from coal seams;

(4) produced from Devonian shale; and

(5) produced under such other conditions as the Commission determines to present extraordinary risks or costs.

(d) Provisions for high-cost natural gas to be elective. —if any credit, exemption, deduction, or comparable adjustment applicable to the computation of any Federal tax is specifically allowable with respect to any high-cost natural gas (or category thereof) under any provision of law enacted after November 9, 1978, the provisions of subsections (a) and (b) of this section and the provisions

of part B of this subchapter shall not apply to such natural gas produced from any well unless an election to have such provisions apply (in lieu of such credit, exemption, deduction, or adjustment) with respect to such natural gas produced from such well is filed with the Commission on or before the later of—

(A) the 30th day after November 9, 1978, under which such credit, exemption, deduction, or adjustment is provided; or

(B) the date the surface drilling of such well began.

(Pub.L. 95-621, Title I, § 707, Nov. 9, 1978, 92 Stat. 3366.)

§ 3318. Ceiling price for stripper well natural gas.

(a) General rule.—In the case of any first sale of stripper well natural gas the maximum lawful price under this section for such natural gas delivered during any month shall be—

(1) $2.09 per million Btu's, in the case of May 1978; and

(2) in the case of any month thereafter, the maximum lawful price, per million Btu's, prescribed under this subsection for the preceding month multiplied by the monthly equivalent of a factor equal to the sum of—

(A) the annual inflation adjustment factor applicable for such month; plus

(B)(i) .035, in the case of any month beginning before April 20, 1981; or

(ii) .04, in the case of any month beginning after April 20, 1981.

(b) Definition of stripper well natural gas.—

(1) General rule.—Except as provided in paragraph (2), the term "stripper well natural gas" means natural gas determined in accordance with section 3413 of this title to be nonassociated natural gas produced during any month from a well if—

(A) during the preceding 90-day production period, such well produced nonassociated natural gas at a rate which did not exceed an average of 60 Mcf per production day during such period; and

(B) during such period such well produced at its maximum efficient rate of flow, determined in accordance with recognized conservation practices designed to maximize the ultimate recovery of natural gas.

(2) Production in excess of 60 Mcf.—The Commission shall, by rule, provide that, if nonassociated natural gas produced from a well which previously qualified as a stripper well under paragraph (1) exceeds an average of 60 Mcf per production day during any 90-day production period, such natural gas may continue to qualify as stripper well natural gas if the increase in nonassociated natural gas produced from such well was the result of the application of recognized enhanced recovery techniques.

(3) Definitions.—For purposes of this subsection—

(A) Production day.—The term "production day" means—

(i) any day during which natural gas is produced; and

(ii) any day during which natural gas is not produced if production such day is prohibited by a requirement of State law or a conservation practice recognized or ap-

proved by the State agency having regulatory jurisdiction over the production of natural gas.

(B) 90-day production period.—The term "90-day production period" means any period of 90 consecutive calendar days excluding any day during which natural gas is not produced for reasons other than voluntary action of any person with the right to control production of natural gas from such well.

(C) Nonassociated natural gas.—The term "nonassociated natural gas" means natural gas which is not produced in association with crude oil.

(Pub.L. 95-621, Title I, § 108, Nov. 9, 1978, 92 Stat. 3367.)

§ 3413. Determinations for qualifying under certain categories of natural gas

(a) General rule.—

(1) Determination.—If any State or Federal agency makes any final determination which it is authorized to make under subsection (c) of this section for purposes of—

(A) applying the definition of new natural gas under section 3312(c) of this title;

(B) deciding if certain natural gas produced from the Outer Continental Shelf qualifies under section 3312(d) of this title for the new natural gas ceiling price;

(C) applying the definition of new, onshore production-well under section 3313(c) of this title;

(D) applying the definition of high-cost natural gas under section 317(c) of this title; or

(E) applying the definition of stripper well natural gas under section 3318(b) of this title;

such determination shall be applicable under this chapter for such purposes unless such determination is reversed under the provisions of subsection (b) of this section or unless such State or Federal agency has waived its authority under the provisions of subsection (c) of this section.

(2) Notice to Commission.—Any Federal or State agency making a determination under paragraph (1) shall provide timely notice in writing of such determination to the Commission. Such notice shall include such substantiation and be in such a manner as the Commission may, by rule, require.

(b) Commission review.—

(1) Authority to review and reverse.—The Commission shall reverse any final State or Federal agency determination described in subsection (a) of this section if—

(A) it makes a finding that such determination is not supported by substantial evidence in the record upon which such determination was made; and

(B) such preliminary finding and notice thereof under paragraph (3) is made within 45 days after the date on which the Commission received notice of such determination under subsection (a)(2) of this section and the final such finding is made within 120 days after the date of the preliminary finding.

(2) Remand on basis of Commission information.—If—

(A) the Commission finds that a State or Federal agency determination is not consistent with information contained in the public records of the Commission, and which is not part of the record upon which such determination was made; and

(B) such preliminary finding and notice thereof under paragraph (3) is made within 45 days after the date on which the Commission received notice of such determination under subsection (a)(2) of this section and the final such finding is made within 120 days after the date of the preliminary finding,

it may remand the matter to such State or Federal agency for consideration of such information. If such agency, after consideration of the information transmitted to it by the Commission, affirms its previous determination, such determination, as so affirmed, shall be subject to review in accordance with this subsection (other than this paragraph).

(3) Notice.—The Commission shall provide notice of any proposed finding under this subsection to the State or Federal agency which made such determination and those parties identified in the notice to the Commission of such determination.

(4) Judicial review of Commission actions.—

(A) Remands.—Any party identified in the notice to the Commission of a determination by a State or Federal agency may obtain review of any final decision by the Commission to remand under paragraph (2) in the United States Court of Appeals for any circuit in which such party is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia circuit. The reviewing

court shall reverse any such decision if it finds such decision is arbitrary or capricious.

(B) Findings.—Any person aggrieved or adversely affected by a final finding of the Commission under paragraph (1) may within 60 days thereafter file a petition for review of such finding in the United States Court of Appeals for any circuit in which the party involved in such determination is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia circuit. The reviewing court shall reverse any such finding of the Commission if the State or Federal agency determination involved is supported by substantial evidence.

(c) State authority.—

(1) General rule.—A Federal or State agency having regulatory jurisdiction with respect to the production of natural gas is authorized to make determinations referred to in subsection (a) of this section.

(2) Waiver.—

(A) In general.—Any Federal or State agency may, in whole or in part, waive its authority to make determinations referred to in subsection (a)(1) of this section by entering into an agreement in accordance with subparagraph (B). If such agency executes such a waiver, the Commission shall, consistent with the agreement, make the determinations which would otherwise be made by such Federal or State agency until the earlier of—

(i) the expiration of the period specified in the agreement; or

(ii) the date such agency transmits to the Commission written notice that it termi-

nates such waiver and assumes the authority to make determinations referred to in subsection (a) (1) of this section.

Any waiver, or termination of any waiver, shall not apply to any determination with respect to any petition therefor which is pending before such agency or the Commission (as the case may be) on the date on which such a waiver or revocation is made.

(B) Agreements.—Any waiver under subparagraph (A) may be made only by a written agreement between the Federal or State agency involved and the Commission. Any such agreement shall set forth the terms and conditions applicable to such waiver.

(3) Procedures applicable.—Determinations of a Federal or State agency referred to in subsection (a) (1) of this section shall be made in accordance with the procedures generally applicable to such agency for the making of such determinations or comparable determinations under the provisions of Federal or State law, as the case may be, pursuant to which they exercise their regulatory jurisdiction. The Commission may prescribe the form and content of filings with a Federal or State agency in connection with determinations made under this section.

(4) Judicial review.—Any such determination referred to in subsection (a) (1) of this section made in accordance with procedures described in paragraph (3) shall not be subject to judicial review under any Federal or State law except as provided under subsection (b) of this section.

(d) Effect of determinations.—For purposes of this chapter.—

(1) General rule.—Any final determination referred to in subsection (a) (1) of this section made

by a Federal or State agency (or by the Commission under subsection (c)(2) of this section) which relates to any natural gas and which is no longer subject to review by the Commission under this section or to judicial review shall thereafter be binding with respect to such natural gas. The preceding sentence shall not apply to any final determination—

(A) if in making such determination the Commission or such Federal or State agency relied on any untrue statement of a material fact; or

(B) if there was omitted a statement of material fact necessary in order to make the statements made not misleading, in light of the circumstances under which they were made, to the Federal or State agency in making such final determination or to the Commission in reviewing such determination.

(2) Application of title 18.—Any untrue statement or omission of material fact to a Federal or State agency upon which the Commission relied shall be deemed to be statement or entry under section 1001 of Title 18.

(e) Interim collection of maximum lawful price.—

(1) Collection of section 3319 price.—

(A) General rule.—Effective beginning on the first day of the first month beginning after November 9, 1978, a seller of natural gas which is produced from a new well may, in accordance with subparagraph (B), charge and collect the appropriate maximum lawful price under section 3319 of this title for any first sale of such natural gas.

(B) Requirements.—A seller may charge and make collections under subparagraph (A) only in accordance with the following requirements:

(i) Sworn statement.—Before any such collection is made, the seller shall file with the Commission, and any Federal or State agency having authority to make determinations referred to in subsection (a) (1) of this section, a written sworn statement that such natural gas is produced from a new well and that such seller believes in good faith that such natural gas is eligible under this chapter to be sold at a price not less than the appropriate maximum lawful price under section 3319 of this title.

(ii) Petition for determination.—Within 90 days after November 9, 1978, the seller files a petition to such Federal or State agency for a determination under this section.

(iii) Collection subject to refund.—Any such collection made by the seller pending a determination under this section shall be collected subject to a condition of refund, with interest, in the event it is determined by such Federal or State agency that the applicable maximum lawful price is lower than that provided under section 3319 of this title.

(2) Alternate interim collection authority.—

(A) General rule.—Promptly after November 9, 1978, the Commission shall, by rule or order, provide one or more methods under which a seller of natural gas may, in accordance with requirements established, and for such period as may be prescribed, under such rule or order, charge and collect for any first sale of such natural gas the maximum lawful price under subchapter I of this chapter for which a petition is filed for a determination under this section in any case in

which such price exceeds the appropriate maximum lawful price under section 3319 of this title.

(B) Collection subject to refund.—Any such collection made by the seller pending a determination under this section shall be collected subject to a condition of refund, with interest. Such refund with interest shall be paid, in accordance with the rule under subparagraph (A), unless it is determined under this chapter that the applicable maximum lawful price is equal to or greater than that collected. In addition, such seller shall comply with such requirements as the Commission shall prescribe in the applicable rule or order to provide adequate assurance that funds, to the extent attributable to a price in excess of the appropriate maximum lawful price under subchapter I of this chapter are available in the event of such refund.

(3) Collection after initial determination.—

(A) General rule.—Effective beginning on the date of the notice of a determination under subsection (a) (2) of this section, a seller of natural gas covered by such determination may, in accordance with subparagraph (B), charge and collect the appropriate maximum lawful price applicable under such determination.

(B) Requirements.—A seller may charge and make collections under subparagraph (A) if such collection is subject to conditions prescribed by the Commission to assure refund, with interest, in the event it is determined under this chapter that the applicable lawful price is lower than that provided under section 3319 of this title.

(Pub.L. 95-621, Title V, § 503, Nov. 9, 1978, 92 Stat. 3397.)

§ 3414. Enforcement

(a) General rule.—It shall be unlawful for any person—

(1) to sell natural gas at a first sale price in excess of any applicable maximum lawful price under this chapter; or

(2) to otherwise violate any provision of this chapter or any rule or order under this chapter.

(b) Civil enforcement.—

(1) In general.—Except as provided in paragraphs (2) and (3), whenever it appears to the Commission that any person is engaged or about to engage in any act or practice which constitutes or will constitute a violation of any provision of this chapter, or of any rule or order thereunder, the Commission may bring an action in the District Court of the United States for the District or Columbia or any other appropriate district court of the United States to enjoin such act or practice and to enforce compliance with this chapter, or any rule or order thereunder.

(2) Enforcement of emergency orders.—Whenever it appears to the President that any person has engaged, is engaged, or is about to engage in acts or practices constituting a violation of any order under section 3362 of this title or any order or supplemental order issued under section 3363 of this title, the President may bring a civil action in any appropriate district court of the United States to enjoin such acts or practices.

(3) Enforcement of incremental pricing.—The Secretary, the Commission, or, on the request of the Secretary or the Commission, the Attorney General, may institute a civil action for injunctive or other equitable relief as may be appropriate to assure compliance with the provisions of section 3345 of this

title requiring the passthrough of surcharges paid under section 3344 of this title by any local distribution company with respect to nautral[1] gas delivered to incrementally priced industrial facilities served by such company. Such action may be instituted in any district court of the United States in the State in which such local distribution company conducts business or in the District Court of the United States for the District of Columbia.

(4) Relief available.—In any action under paragraph (1), (2), or (3), the court shall, upon a proper showing, issue a temporary restraining order or preliminary or permanent injunction without bond. In any such action, the court may also issue a mandatory injunction commanding any person to comply with any applicable provision of law, rule, or order, or ordering such other legal or equitable relief as the court determines appropriate, including refund or restitution.

(5) Criminal referral.—The Commission may transmit such evidence as may be available concerning any acts or practices constituting any possible violations of the Federal antitrust laws to the Attorney General who may institute appropriate criminal proceedings.

(6) Civil penalties.—

(A) In general.—Any person who knowingly violates any provision of this chapter, or any provision of any rule or order under this chapter, shall be subject to—

(i) except as provided in clause (ii) a civil penalty, which the Commission may assess, of not more than $5,000 for any one violation; and

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[1] So in original. Probably should be "natural".

(ii) a civil penalty, which the President may assess, of not more than $25,000, in the case of any violation of an order under section 3362 of this title or an order or supplemental order under section 3363 of this title.

(B) Definition of knowing.—For purposes of subparagraph (A), the term "knowing" means the having of—

(i) actual knowledge; or

(ii) the constructive knowledge deemed to be possessed by a reasonable individual who acts under similar circumstances.

(C) Each day separate violation.—For purposes of this paragraph, in the case of a continuing violation, each day of violation shall constitute a separate violation.

(D) Statute of limitations.—No person shall be subject to any civil penalty under this paragraph with respect to any violation occurring more than 3 years before the date on which such person is provided notice of the proposed penalty under subparagraph (E). The preceding sentence shall not apply in any case in which an untrue statement of material fact was made to the Commission or a State or Federal agency by, or acquiesced to by, the violator with respect to the acts or omissions constituting such violation, or if there was omitted a material fact necessary in order to make any statement made by, or acquiesced to by, the violator with respect to such acts or omissions not misleading in light of circumstances under such statement was made.

(E) Assessed by commission.—Before assessing any civil penalty under this paragraph, the Commission shall provide to such person notice

of the proposed penalty. Following receipt of notice of the proposed penalty by such person, the Commission shall, by order, asssess[2] such penalty.

(F) Judicial review.—If the civil penalty has not been paid within 60 calendar days after the assessment order has been made under subparagraps (E), the Commission shall institute an action in the appropriate district court of the United States for an order affirming the assessment of the civil penalty. The court shall have authority to review de novo the law and the facts involved, and shall have jurisdiction to enter a judgment enforcing, modifying, and enforcing as so modified, or setting aside in whole or in part, such assessment.

(c) Criminal penalties.—

(1) Violation of chapter.—Except in the case of violations covered under paragraph (3), any person who knowingly and willfully violates any provision of this chapter shall be subject to—

(A) a fine or not more than $5,000; or

(B) imprisonment for not more than two years; or

(C) such fine and such imprisonment.

(2) Violation of rules or orders generally.—Except in the case of violations covered under paragraph (3), any person who knowingly and willfully violates any rule or order under this chapter (other than an order of the Commission assessing a civil penalty under subsection (b)(4)(E) of this section), shall be subject to a fine of not more than $500 for each violation.

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[2] So in original. Probably should be "assess".

(3) Violations of emergency orders.—Any person who knowingly and willfully violates an order under section 3362 of this title or an order or supplemental order under section 3363 of this title shall be fined not more than $50,000 for each violation.

(4) Each day separate violation.—For purposes of this subsection, each day of violation shall constitute a separate violation.

(5) Definition of knowingly.—For purposes of this subsection, the term "knowingly"; when used with respect to any act or omission by any person, means such person—

(A) had actual knowledge; or

(B) had constructive knowledge deemed to be possessed by a reasonable individual who acts under similar circumstances.

(Pub.L. 95-621, Title V, § 504, Nov. 9, 1978, 92 Stat. 3401.)

SUBCHAPTER VI—COORDINATION WITH NATURAL GAS ACT; MISCELLANEOUS PROVISIONS

§ 3431. Coordination with Natural Gas Act

(a) Jurisdiction of Commission under Natural Gas Act.—

(1) Sales.—

(A) Natural gas not committed or dedicated. —For purposes of section 1(b) of the Natural Gas Act, effective on the first day of the first month beginning after November 9, 1978, the provisions of the Natural Gas Act and the jurisdiction of the Commission under such Act shall not apply to natural gas which was not committed or dedicated to interstate commerce as of November 8, 1978, solely by reason of any first sale of such natural gas.

(B) Committed or dedicated natural gas.—Effective beginning on the first day of the first month beginning after November 9, 1978, for purposes of section 1(b) of the Natural Gas Act, the provisions of such Act and the jurisdiction of the Commission under such Act shall not apply solely by reason of any first sale of natural gas which is committed or dedicated to interstate commerce as of November 8, 1978, and which is—

(i) high-cost natural gas (as defined in section 3317(c)(1), (2), (3), or (4) of this title);

(ii) new natural gas (as defined in section 3312(c) of this title); or

(iii) natural gas produced from any new, onshore production well (as defined in section 3313(c) of this title).

(C) Authorized sales or assignments.—For purposes of section 1(b) of the Natural Gas Act, the provisions of the Natural Gas Act and the jurisdiction of the Commission under such Act shall not apply by reason of any sale of natural gas—

(i) authorized under section 3362(a) or 3371(b) of this title; or

(ii) pursuant to any assigned[1] authorized under section 3372(a) of this title.

(D) Natural-gas company.—For purposes of the Natural Gas Act, the term "natural-gas company" (as defined in section 2(6) of such Act) shall not include any person by reason of, or with respect to, any sale of natural gas if the provisions of the Natural Gas Act and the jurisdiction of the Commission do not apply to such sale solely by reason of subparagraph (A), (B), or (C) of this paragraph.

(E) Alaskan natural gas.—Subparagraph (B)(ii) and (iii) shall not apply with respect to natural gas produced from the Prudhoe Bay unit of Alaska and transported through the transportation system approved under the Alaska Natural Gas Transportation Act of 1976.

(2) Transportation.—

(A) Jurisdiction of the Commission.—For purposes of section 1(b) of the Natural Gas Act the provisions of such Act and the jurisdiction of the Commission under such Act shall not apply to any transportation in interstate commerce of natural gas if such transportation is—

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[1] So in original. Probably should be "assignment".

(i) pursuant to any order under section 3362(c) or section 3363(b), (c), (d), or (h) of this title; or

(ii) authorized by the Commission under section 3371(a) of this title.

(B) Natural-gas company.—For purposes of the Natural Gas Act, the term "natural-gas company" (as defined in section 2(6) of such Act) shall not include any person by reason of, or with respect to, any transportation of natural gas if the provisions of the Natural Gas Act and the jurisdiction of the Commission under the Natural Gas Act do not apply to such transportation by reason of subparagraph (A) of this paragraph.

(b) Charges deemed just and reasonable.—

(1) Sales.—

(A) First sales.—Subject to paragraph (4), for purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any first sale of natural gas shall be deemed to be just and reasonable if—

(i) such amount does not exceed the applicable maximum lawful price established under subchapter I of this chapter; or

(ii) there is no applicable maximum lawful price solely by reason of the elimination of price controls pursuant to part B of subchapter I of this chapter.

(B) Emergency sales.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any sale authorized under section 3362(a) of this title shall be deemed to be just and reasonable if such amount does not exceed the fair and equitable price established under such section and applicable to such sale.

(C) Sales by intrastate pipelines.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid in any sale authorized by the Commission under section 3371(b) of this title shall be deemed to be just and reasonable if such amount does not exceed the fair and equitable price established by the Commission and applicable to such sale.

(D) Assignments.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid pursuant to the terms of any contract with respect to that portion of which the Commission has authorized an assignment authorized under section 3372(a) of this title shall be deemed to be just and reasonable if such amount does not exceed the applicable maximum lawful price established under subchapter I of this chapter.

(E) Affiliated entities limitation.—For purposes of paragraph (1), in the case of any first sale between any interstate pipeline and any affiliate of such pipeline, any amount paid in any first sale shall be deemed to be just and reasonable if, in addition to satisfying the requirements of such paragraph, such amount does not exceed the amount paid in comparable first sales between persons not affiliated with such interstate pipeline.

(2) Other charges.—

(A) Allocation.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid by any interstate pipeline for transportation, storage, delivery or other services provided pursuant to any order under section 3363(b), (c), or (d) of this title shall be deemed to be just and reasonable if such amount is prescribed by the President under Section 3363(h)(1) of this title.

(B) Transportation.—For purposes of sections 4 and 5 of the Natural Gas Act, any amount paid by any interstate pipeline for any transportation authorized by the Commission under section 3371(a) of this title shall be deemed to be just and reasonable if such amount does not exceed that approved by the Commission under such section.

(c) Guaranteed passthrough.—

(1) Certificate may not be denied based upon price.—The Commission may not deny, or condition the grant of, any certificate under section 7 of the Natural Gas Act based upon the amount paid in any sale of natural gas, if such amount is deemed to be just and reasonable under subsection (b) of this section.

(2) Recovery of just and reasonable prices paid.—For purposes of sections 4 and 5 of the Natural Gas Act, the Commission may not deny any interstate pipeline recovery of any amount paid with respect to any purchase of natural gas if—

(A) under subsection (b) of this section, such amount is deemed to be just and reasonable for purposes of sections 4 and 5 of such Act, and

(B) such recovery is not inconsistent with any requirement of any rule under section 3341 of this title (including any amendment under section 3342 of this title),

except to the extent the Commission determines that the amount paid was excessive due to fraud, abuse, or similar grounds.

(Pub.L. 95-621, Title VI, § 601, Nov. 9, 1978, 92 Stat. 3409.)

APPENDIX D

FEDERAL ENERGY REGULATORY COMMISSIONS REGULATIONS

CODE OF FEDERAL REGULATIONS
TITLE 18

PART 271—CEILING PRICES

Subpart A—Summary Tables and Calculations

§ 271.101 Ceiling prices for certain categories of natural gas.

(a) The maximum lawful price for natural gas subject to Subparts B, C, G, H, and I of this part, and certain natural gas subject to Subpart F thereof, are specified in Table I. The maximum lawful prices for certain categories of natural gas subject to Subpart D of this part are specified in Table II.

[Tables I and II Omitted in Printing]

§ 271.305 Special rule applicable to existing proration units.

(a) *Applicability.* (1) This section applies only to a jurisdictional agency determination with respect to a new well which is within a State law proration unit:

(i) Which was in existence at the time the surface drilling of such well began;

(ii) Which was applicable to the reservoir from which natural gas from such well is produced; and

(iii) Which applied to a well:

(A) Which produced natural gas in commercial quantities; or

(B) The surface drilling of which was begun before February 19, 1977, and which was thereafter capable of producing natural gas in commercial quantities.

(2) For purposes of this paragraph, State law proration unit means a proration unit, drilling unit or similar unit expressly designated in accordance with State law or Federal law (other than the NGPA).

(b) *Wells spudded on or after February 19, 1977.*

(1) In order for natural gas from a well to which this section applies to qualify for the maximum lawful price under this subpart, the jurisdictional agency must explicitly find that the well is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit. This explicit finding must be based on appropriate geological and engineering data and such data must be included in the notice of determination submitted to the Commission.

(2) [Reserved]

(c) *Notice of finding.* If the jurisdictional agency makes a finding under paragraph (b)(1) of this section, it shall notify the Commission of such a determination in accordance with § 274.104.

(d) *Rebuttable presumption for certain wells drilled on existing proration units.* For the purposes of section 103(c)(3)(C) of the NGPA and paragraph (a)(1)(iii) of this section, if a well has been plugged and abandoned prior to January 1, 1970 and has not produced natural gas on or after that date, a rebuttable presumption is created that the well has not produced and is not capable of producing natural gas in commercial quantities.

APPENDIX E

[61,476]

[¶61,207]

Docket No. GP84-23-000

STOWERS OIL & GAS COMPANY, *et al.*

ORDER INITIATING SHOW CAUSE PROCEEDING AND PRESCRIBING EXPEDITED PROCEDURES

(Issued February 15, 1985)

Before Commissioners: Raymond J. O'Connor, Chairman; Georgiana Sheldon, J. David Hughes, A. G. Sousa and Oliver G. Richard III.

I.

A preliminary investigation has been conducted by the Enforcement Division of the Office of the General Counsel under the Commission's Rules Relating to Investigations, 18 C.F.R. Part 1b (1983), into certain sales of natural gas produced from the West Panhandle Field, Carson and Gray Counties, Texas. As a result of the preliminary investigation, information has been reported to the Commission alleging that certain oil well operators may have engaged and may be engaging in acts and practices which violate the Natural Gas Act ("NGA"), 15 U.S.C. § 717, *et seq.* (1982), the Natural Gas Policy Act of 1978 ("NGPA"), 15 U.S.C. § 3301, *et seq.* (1982), and the Commission's regulations thereunder.

Thirty-seven oil well operators are named as respondents in this proceeding. These operators, the identity and location of the wells which they operate, and other information is set forth in the table annexed hereto as Appendix A, which is incorporated herein and made a part hereof. The facts alleged in Section II of this order describe the acts and [61,477] practices which are the subject of this proceeding.

II.

1. On or about July 1, 1954, Dorchester Corporation, a parent corporation of Dorchester Gas Producing Company ("Dorchester"), acquired by conveyance from Nalam Corporation the interest in gas produced from all formations lying in whole or in part above sea level on certain acreage in the West Panhandle Field, Carson and Gray Counties, Texas (the "subject acreage"). Dorchester did not acquire any interest in oil, nor any interest in gas formations lying wholly below sea level.

2. By contract dated July 1, 1952 (the "1952 Contract"), Dorchester's predecessors in interest had dedicated to Northern Natural Gas Company ("Northern"), an interstate natural gas pipeline company, "all of its gas rights in the gas lands and leases covering the [subject] acreage . . . together with all wells now drilled or hereafter to be drilled on such acreage . . . . ," as that acreage is described in the Exhibits to the 1952 Contract.

3. On November 26, 1954, Dorchester filed with the Commission an application in Docket No. G-5925 for a certificate of public convenience and necessity pursuant to Section 7(c) of the NGA covering sales to Northern under the 1952 Contract, which was incorporated by reference into the application.

4. By order issued February 6, 1956 in Docket No. G-4568, *et al.*, the Commission issued a certificate of public convenience and necessity to Dorchester covering sales to Northern under the 1952 Contract, as more fully described in the certificate application.

5. Dorchester accepted the certificate of public convenience and necessity and continued sales to Northern of natural gas produced from the subject acreage.

6. Dorchester presently operates numerous gas wells on the subject acreage, of which 36 are primarily affected by the acts and practices which are the subject of this

order. All gas produced from these 36 gas wells is sold to Northern at the applicable maximum lawful price under the NGPA.

7. Each of these 36 affected gas wells, which are also identified on Appendix A, has been assigned a specific "proration unit" by the State of Texas for gas allocation purposes. For all but six such gas wells, the assigned proration units each consist of 640 acres.

8. In most cases, the boundaries of the proration units assigned to these 36 Dorchester gas wells are coextensive with the boundaries of survey sections established by original railroad surveys. These survey sections are typically identified by Block and Section number with in a particular survey.[1] In some cases, however, the proration unit assigned to a particular Dorchester gas well is not coextensive with the boundaries of a particular survey section, and may extend into other adjacent survey sections.

9. The proration units assigned to the 36 Dorchester gas wells are located in the following Blocks and Sections, all of which are within the areal limits of the acreage dedicated under the 1952 Contract by Dorchester to Northern: Block B-2, Sections 113, 114, 115, 117, 126, 127, 128, 144, 153, 182, 183, 206, 208, 209, 210, 211, 239, 241, 242, and 243; Block 3, Sections 108, 109, 133, 134, 155, 156, 157, 158, 176, 177, 182, 184, 202, and 204; Block 4, Sections 1, 2, 16, 21, 22, and 46; and Block 7, Sections 1, 6, 7, 16, 22, 23, and 69.

10. The 36 Dorchester gas wells were completed between 1934 and 1949 into the brown dolomite formation (or stratum), and from the date of their completion to the present, each Dorchester gas well has produced from the brown dolomite formation only natural gas, and no crude oil or condensate.

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[1] In this order, the designations of the I & GN Railroad survey are used to locate individual wells by Block and Section number.

11. The brown dolomite formation is one of four separate strata, and is the primary gas-bearing formation, within the West Panhandle Field.

12. Primarily between 1980 and the present,[2] each of the respondents drilled or caused to be drilled one or more oil wells within the areal limits of the proration units described in paragraph 9, above.

13. Each of these oil wells was initially completed in the granite wash formation (or stratum), which lies below the brown dolomite formation.

14. Prior to Dorchester's acquisition of its gas rights in the leases comprising the subject acreage, the original mineral interest owners assigned to a third party all right, title and interest in and to the same oil and gas mineral leases "insofar as said leases and leasehold estates cover the oil and oil rights only in and to the producing horizons thereunder . . . ." The assignment expressly provides that it does not cover or include any right, title or interest with respect to the gas or gas rights in, to and under said leaseholds.

15. Each of the respondents acquired an interest in oil rights in its respective portion of the subject acreage either by assignment from the successors in interest to the original mineral interest owners or, more commonly, by execution of a farmout agreement with the successors in interest to the original mineral interest owners.

[61,478] 16. The instruments of assignment typically are simple conveyances which make reference to an executed farmout agreement, and the assignment is made "in strict accordance" with the terms and provisions of the farmout agreement.

17. The typical farmout agreement states:

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[2] The date on which each oil well was completed is set forth in Appendix A.

It is expressly provided that this Farmout Agreement does not cover or apply to dry gas rights in and under the lands described on Exhibit "A" and that Farmees shall set and cement casing in all wells drilled hereunder in such a manner as to prevent gas well gas from entering the oil zones. In no event shall any dry gas produced from gas zones be produced with the oil or casinghead gas produced by Farmees.

18. Each of the respondents identified in Appendix A of this order has the right to produce and sell oil from its respective portion of the subject acreage.

19. Dorchester has the right to produce and sell dry gas from the subject acreage.

20. All dry gas produced from the subject acreage is gas which is "committed or dedicated to interstate commerce" under NGPA Section 2(18)(A)(ii), 15 U.S.C. § 3301(18)(A)(ii) (1982).

21. Each of the respondents identified in Appendix A may have the right to produce and sell casinghead gas from its respective portion of the subject acreage.[3]

22. Even if each of the respondents identified in Appendix A of this order has the right to produce and sell casinghead gas from its respective portion of the subject acreage, and even if casinghead gas were not committed or dedicated to interstate commerce, none of the respondents has the right to produce and sell dry gas from its respective portion of the subject acreage.

Apparent Violations of NGA Section 7(b)

23. "Dry gas" means gas produced from a stratum that does not produce oil. Tex. [Nat. Res.] Code Ann. § 86.002(7) (Vernon 1978).

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[3] The question of title to casinghead gas is being litigated in Texas state court, and is not in issue in this proceeding.

24. "Casinghead gas" means any gas or vapor indigenous to an oil stratum and produced from the stratum with oil. Tex. [Nat. Res.] Code Ann. § 86.002(10) (Vernon 1978).

25. Section 86.097 of the Texas Natural Resources Code ("Code") provides that "no person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only." Tex. [Nat. Res.] Code Ann. § 86.097 (Vernon 1978).

26. The respective operator of each of the oil wells identified in Appendix A has perforated the well bore or has caused the well bore to be perforated in the brown dolomite stratum at or near the level of the producing interval of the Dorchester gas well within whose proration unit each such oil well is situated.

27. In most cases, the perforations of the well bore in the brown dolomite stratum were made after each oil well was initially completed in the granite wash stratum, and such additional up-hole perforations (or completion locations) were not reported to the Texas Railroad Commission.

28. Each of the oil wells identified in Appendix A of this order has been completed so as to cause natural gas from the brown dolomite stratum to be produced.

29. The brown dolomite stratum is productive only of dry gas at the level at which the operators of each of the oil wells identified in Appendix A have perforated or have caused the perforation of such oil wells.

30. By virtue of the production of dry gas from the brown dolomite stratum, the operators of the oil wells identified in Appendix A have drained approximately 8.6 Bcf of gas reserves dedicated by Dorchester to interstate commerce.

31. Section 7(b) of the NGA, 15 U.S.C. § 717f(b) (1982), provides:

No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

32. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, has produced and sold, is producing and selling, and is about to produce and sell in intrastate commerce [4] natural gas which has been dedicated to interstate commerce, thereby abandoning service subject to the jurisdiction of the Commission without the Commission's prior permission and approval pursuant to NGA Section 7(b), 15 U.S.C. § 717f(b).

33. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, has failed to file [61,479] an application for abandonment, by which such prior permission and approval must be sought with respect to such abandonment under the Commission's regulations at 18 C.F.R. § 157.30 (1983).

34. Each of the respondents identified in Appendix A of this order, with the exception of Tonya Starbuck, K. A.

[4] The intrastate purchasers are identified in Appendix A; gas produced by oil wells operated by Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins is sold exclusively to Northern, the dedicated purchaser.

Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas, L. R. Spradling and V. T. Stowers, d/b/a Stowers Oil & Gas Co., and J. B. Watkins, appears to have violated, appears to be violating, and appears to be about to violate Section 7(b) of the NGA, 15 U.S.C. § 717f(b), and the Commission's regulations thereunder, 18 C.F.R. § 157.30.

Apparent Violations of NGPA Section 504

35. Dry gas is considered to be "natural gas" under Section 2(1) of the NGPA, 15 U.S.C. § 3301(1) (1982).

36. Section 2(21)(A) of the NGPA, 15 U.S.C. § 3301 (21)(A) (1982), defines a "first sale" of natural gas as, *inter alia,* any sale of any volume of natural gas to any interstate pipeline or intrastate pipeline.

37. At all relevant times, the sales by each of the respondents of all natural gas produced from the oil wells identified in Appendix A of this order were "first sales" within the meaning of NGPA Section 2(21)(A).

38. Section 104 of the NGPA, 15 U.S.C. § 3314 (1982), establishes, pursuant to a pricing formula, the maximum lawful prices at which natural gas "committed or dedicated to interstate commerce" as of November 8, 1978, and for which a just and reasonable rate under the NGA was in effect on that date, may be sold in any "first sale" of such natural gas.

39. Dry gas produced and sold from the subject acreage was natural gas "committed or dedicated to interstate commerce" as of November 8, 1978, as defined in Section 2(18)(A)(ii) of the NGPA, 15 U.S.C. § 3301 (18)(A)(ii).

40. A just and reasonable rate under the NGA was in effect on November 8, 1978, for dry gas produced from the subject acreage.

41. All dry gas produced from the subject acreage must be sold at the maximum lawful price established by

Section 104 of the NGPA, 15 U.S.C. § 3314, and the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 and 271.402 (1983), in any first sale, except to the extent that a particular well producing such dry gas has qualified for pricing under some other section of NGPA Title I.

42. A "proration unit" as defined in NGPA Section 2(8), 15 U.S.C. § 3301(2)(8) (1982), is that portion of a reservoir, as designated by the agency having regulatory jurisdiction with respect to production from such reservoir, which will be effectively and efficiently drained by a single well.

43. Each of the respondents identified in Appendix A of this order, with the exception of the Harlow Corporation, Walker Operating Corporation, and J. B. Watkins, has filed an application for a well category determination under Section 103 of the NGPA, 15 U.S.C. § 3313 (1982) (new onshore production wells), for all or some of the oil wells identified in Appendix A operated by such respondent.

44. The well category determination applications filed by the respondents identified in paragraph 43, with the exception of the applications for determination filed by Dahalo Lease Corporation and Lear Oil & Gas, Inc., have been affimatively determined by the State jurisdictional agency, and those affirmative Section 103 determinations have become final.

45. None of the respondents whose oil wells have received final, affirmative NGPA Section 103 well category determinations in the dockets identified in Appendix A of this order has obtained pursuant to 18 C.F.R. § 271.305 (1983) an explicit finding from the Texas Railroad Commission that the well for which a determination was sought is necessary to effectively and efficiently drain the brown dolomite formation, which is the portion of the reservoir drained by, and covered by a proration unit assigned to, an existing Dorchester gas well.

46. Each of the final, affirmative NGPA Section 103 well category determinations received by the respondents identified in Appendix A of this order relates *only* to the sale of casinghead gas, and not to the sale of dry gas, produced from each such oil well.

47. Each of the respondents identified in Appendix A of this order, with the exception of the Harlow Corporation, Walker Operating Corporation, and J. B. Watkins, has charged and collected, is charging and collecting, and is about to charge and collect maximum lawful prices under Section 103 of the NGPA, 15 U.S.C. § 3313, for dry gas produced from one or more of the oil wells which each respectively operates.

48. Dahalo Lease Corporation; the Harlow Corporation; Kim Petroleum Co., Inc.; Tonya Starbuck, K. A. Roberts, and V. T. Stowers, d/b/a Komanche Oil & Gas; Meyer Farms Inc.; Sharon Caldwell Ward, d/b/a Sharon Lease Oil Co.; Walker Operating Corporation, J. B. Watkins; and Wy-Vel Corp. have charged and collected, are charging and collecting, and are about to charge and collect maximum [61,480] lawful prices under Section 109 of the NGPA, 15 U.S.C. § 3319 (1982), for dry gas produced from one or more of the oil wells which each respectively operates.

49. Each of the respondents identified in Appendix A of this order has charged and collected, is charging and collecting, and is about to charge and collect a rate for a first sale of dry gas produced from one or more oil wells which each respectively operates in excess of the applicable maximum lawful price under Section 104 of the NGPA and the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 and 271.402.

50. Each of the respondents identified in Appendix A of this order appears to have violated, appears to be violating, and appears to be about to violate Section 504(a)(1) of the NGPA, 15 U.S.C. § 3414(a)(1) (1982) and

the Commission's regulations thereunder, 18 C.F.R. §§ 271.101 anud 271.402.

III.

A. The Commission neither makes findings of fact nor reaches conclusions of law with regard to the respondents' alleged acts and practices. However, the allegations set forth in Section II of this order raise the possibility that inexpensive dedicated gas reserves have been and are being irrevocably drained from the interstate market and sold at unlawfully high rates. Because of the seriousness of these allegations, the Commission finds it appropriate that this matter be resolved expeditiously. Therefore, in setting this matter for hearing before an administrative law judge, we are establishing procedures to promote a speedy, efficient and fair resolution consistent with our responsibilities to vigorously enforce the provisions of the NGA and NGPA.

To this end, the proceeding shall be conducted in two phases. The first phase will resolve the issue of the respondents' alleged violations of law. If the alleged acts and practices of the respondents are determined to constitute violations of the NGA, the NGPA, and/or the Commission's regulations thereunder, then there shall be a second phase of the proceeding. The second phase will resolve the issue of the extent of the violations and the appropriate monetary remedies to be imposed by the Commission in connection therewith, including, but not limited to, requiring disgorgement by the respondents of any revenues unlawfully collected. However, if, during the first phase, it is determined that violations of the NGA or NGPA are on-going, then prior to the commencement of the second phase, it shall also be determined whether an order prohibiting the respondents from violating the NGA and/or the NGPA is appropriate.

The second phase will be held in abeyance pending the resolution of the first phase. We believe that a phasing of the proceeding will speed up the decisional process by

postponing consideration of, and the need to gather and adduce evidence concerning, such remedial issues as the total volume of gas diverted and the revenues collected in connection therewith. These matters need not be addressed until after it is determined whether the alleged acts and practices of the respondents violate the NGA, the NGPA, and/or the Commission's regulations thereunder.

The issues to be addressed in the hearing and briefs in the first phase of this proceeding are:

(1) Whether the respondents have produced and sold, are producing and selling, or are about to produce and sell in intrastate commerce natural gas which is committed or dedicated to interstate commerce without having sought or obtained the prior permission and approval of the Commission pursuant to Section 7(b) of the NGA?

(2) Whether the respondents have charged and collected, are charging and collecting, or are about to charge and collect a price in connection with any first sale of natural gas which is committed or dedicated to interstate commerce which is in excess of the applicable maximum lawful price under Section 104 of the NGPA?

The Commission intends to issue its decision in this matter at the earliest possible date.

B. By separate order today [26 FERC ¶ 61,208], we are dismissing the petitions for declaratory order filed by Stowers Oil & Gas Company, *et al.*, and by Northern Natural Gas Company, division of InterNorth, Inc.,[5] both of which relate to the acts and practices which are the subject of this proceeding. The dockets in which those petitions were filed are terminated by that order. Petitioners who intervened in those dockets must intervene

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[5] Docket No. GP84-5-000, filed October 26, 1983 and Docket No. GP84-7-000, filed October 28, 1983, respectively.

in this docket if they wish to become parties in this proceeding.

C. We recognize that the acts and practices which are the subject of this proceeding may not be confined to acreage which has been dedicated to interstate commerce by Dorchester.[6] To the extent that similar acts and practices occurring on other dedicated acreage involve questions of law which are in comon with those to be addressed in this proceeding, the Commission invites those who may be affected by them to [61,481] intervene in this proceeding for the limited purpose of briefing those legal questions. However, the Commission would view with disfavor any attempt to expand the scope of this proceeding to include facts relating to similar acts and practices which may be occurring on acreage other than Dorchester's. The Enforcement Division has been directed to continue its preliminary investigation of such similar acts and practices.

The Commission finds:

(1) Good cause exists for requiring, and the public interest in administering the NGA and NGPA demands, that each respondent identified in Appendix A show cause why that respondent should not be found to have violated Section 7(b) of the NGA, Section 504(a)(1) of the NGPA, and the Commission's regulations thereunder as a result of the acts and practices which are the subject of this order. Each respondent shall show cause why the Commission should not order any or all appropriate remedies including, but not limited to, prohibiting that respondent from engaging in acts and practices which con-

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[6] A petition for declaratory order alleging that similar acts and practices are occurring on its dedicated acreage in the West Panhandle Field has been filed by Colorado Interstate Gas Company ("CIG") in Docket No. GP84-8-000. This petition shall be held in abeyance, pending the conclusion by the Enforcement Division of its preliminary investigation of CIG's allegations.

stitute violations of the NGA, prohibiting that respondent from charging and collecting rates for sales of natural gas from the subject oil wells in excess of the applicable maximum lawful price for such sales under the NGPA, and requiring that respondent to disgorge any revenues unlawfully collected in connection with such sales, together with interest computed under 18 C.F.R. § 154.102(c).

(2) In view of the fact that the allegations set forth in Section II of this order, if true, raise the possibility that inexpensive gas reserves have been and are being irretrievably drained from the interstate market and sold at unlawfully high rates, there is good cause to waive any provision of the Commission's Rules of Practice and Procedure which may be inconsistent with the expedited procedures prescribed by this order, which procedures the Commission has determined to be appropriate in this matter.

The Commission orders:

(A) Pursuant to Rule 209 of the Commission's Rules, 18 C.F.R. § 385.209, a show cause proceeding is hereby initiated against the respondents identified in Appendix A of this order.

(B) Each respondent shall show cause why that respondent should not be found to have violated Section 7(b) of the NGA, Section 504(a)(1) of the NGPA, and the Commission's regulations thereunder as a result of the acts and practices alleged in Section II of this order. Each respondent shall show cause why the Commission should not order any or all appropriate remedies, including but not limited to, prohibiting that respondent from engaging in acts and practices which constitute violations of the NGA, prohibiting that respondent from charging and collecting rates for sales of natural gas from the subject oil wells in excess of the applicable maximum lawful price for such sales under the NGPA, and requir-

ing that respondent to disgorge any revenues unlawfully collected in connection with such sales, together with interest computed under 18 C.F.R. § 154.102(c).

(C) Each respondent's answer to this order shall be filed pursuant to Rule 213 of the Commission's Rules, 18 C.F.R. § 385.213, in writing and under oath, on or before 15 days after the date of this order. Accordingly, each respondent shall admit or deny, specifically and in detail, each allegation set forth in Section II of this order as it pertains to each such respondent, and each respondent shall set forth every defense relied on.

(D) Pursuant to Sections 4, 7, 15 and 16 of the NGA, Section 501 of the NGPA, and Rule 601 of the Commission's Rules, 18 C.F.R. § 385.601, a prehearing conference shall be convened in this proceeding in a hearing room of the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, within 20 days after the date of this order at 10:00 a.m. Eastern Daylight Time. Each respondent shall be fully prepared, as set forth in Rule 601(b) of the Commission's Rules, 18 C.F.R. § 385.601(b), to discuss any and all matters to be considered at the conference.

(E) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge, shall preside at the prehearing conference in this proceeding, with authority to establish and change procedural dates and to rule on motions, all as provided for in the Commission's Rules, 18 C.F.R. Part 385.

(F) This proceeding shall be phased. The first phase shall resolve the issue of the respondents' alleged violations of law. If the alleged acts and practices of the respondents are determined to constitute violations of the NGA, NGPA and/or the Commission's regulations thereunder, then there shall be a second phase of the proceeding to determine the appropriate monetary remedies to be imposed by the Commission in connection therewith. How-

ever, if during the first phase of the proceeding it is determined that violations of the NGA or NGPA are ongoing, then prior to the commencement of the second phase, it shall also be determined whether an order [61,482] prohibiting the respondents from violating the NGA and/or NGPA is appropriate.

(G) The presiding administrative law judge shall establish an expedited hearing date for a full hearing on the merits. The judge shall conduct all hearings pursuant to Rule 501, *et seq.*, of the Commission's Rules, 18 C.F.R. § 385.501, *et seq.*, and has all authority delegated by Rule 504 of the Commission's Rules, 18 C.F.R. § 385. 504.

(H) Pursuant to Rule 709 of the Commission's Rules, 18 C.F.R. § 385.709, the presiding administrative law judge shall not render an initial decision. Instead, after completion of the expedited hearing, the presiding administrative law judge shall, pursuant to 5 U.S.C. § 557(b) and Rule 709 of the Commission's Rules, 18 C.F.R. § 385.709, promptly render a recommended decision and certify the entire record to the Commission for decision. Prior to rendering a recommended decision, and consistent with our directive that this matter be resolved expeditiously, the presiding administrative law judge shall permit parties a reasonable opportunity to submit for consideration, either in writing or orally, as is determined to be appropriate in the circumstances, proposed findings and conclusions and the reasons supporting such findings and conclusions. There being no initial decision, no briefs on exceptions and no briefs opposing exceptions shall be filed with the Commission under Rule 711 of the Commission's Rules, 18 C.F.R. § 385.711.

(I) Since many of the facts pertinent to the issues in this proceeding are within the particular knowledge of the respondents and/or their employees and agents, Enforcement Staff shall be permitted liberal discovery in

this proceeding. To further promote the expeditious resolution of this proceeding, the Commission supplements its discovery rules by providing that a participant or party may serve upon any other participant or party a written request for the admission, for the purposes of this proceeding only, of the truth of any matters that relate to statements or opinions of fact or of the application of law to fact, including the genuineness of any documents described in the request. Each matter of which an admission is requested shall be separately set forth, and the matter is admitted unless, within 30 days after service of the request, or within such shorter or longer time as the presiding administrative law judge may allow, the participant or party to whom the request is directed serves upon the participant or party requesting the admission a written answer or objection addressed to the matter, signed by the participant or party or by its attorney.

(J) Each respondent shall, within 30 days after the date of this order, produce with respect to *each* of the oil wells identified in Appendix A operated by such respondent, the following information and/or documents to the presiding administrative law judge, for inspection and reproduction by Enforcement Staff:

(1) Copies of all electrical, acoustical, radio-active or other logs run on such wells, including, but not limited to, porosity logs (FDC-CNL and Gamma Ray neutron), sonic logs and resistivity logs;

(2) Copies of all computer logs run on such wells, including, but not limited to, Cyberlook;

(3) Copies of cement bond logs and perforating depth control logs run on such wells; and

(4) Copies of work-over records, including service tickets by logging and/or perforating companies.

(K) If the presiding administrative law judge determines that there is evidence of sales of natural gas pro-

duced by oil wells on Dorchester's subject acreage in the West Panhandle Field other than those identified in Appendix A of this order or operated by entities other than those identified in Appendix A of this order, the presiding administrative law judge may expand the scope of this proceeding to include such entities as respondents and to place such sales at issue in this proceeding.

(L) Pursuant to Rule 101(e) of the Commission's Rules, 18 C.F.R. § 385.101(e), for good cause, the Commission hereby waives any provision of the Commission's Rules which may be inconsistent with the procedures prescribed by this order for this proceeding.

(M) Petitions for intervention shall be filed no later than 15 days after the date of this order. Any person who has filed a petition to intervene in Docket No. GP84-5-000 or GP84-7-000 must file a petition to intervene in this proceeding to be considered a party to this proceeding. Any person who has filed a petition to intervene in Docket No. GP84-8-000 must also file a petition to intervene in this proceeding, but participation in this proceeding shall be for the limited purpose of briefing common questions of law.

[Appendix A Omitted in Printing]

APPENDIX F

[¶ 63,048]

Docket No. GP84-23-000

STOWERS OIL & GAS COMPANY, *et al.*

Motion to Compel Denied

(Issued April 20, 1984)

Brenda P. Murray, Administrative Law Judge.

On April 12, 1984, Anadarko Production Company (Anadarko) and Pan Eastern Exploration Company (Pan Eastern) filed a motion to compel the Stowers Oil & Gas Company, *et al.* (Producer Group) to answer Interrogatories, Request for Production and Inspection, and Request for Admission served on March 9, 1984. Movants claim their discovery requests are modelled on the Producer Group's discovery requests to Staff. They argue they are relevant to show that the Producer Group's "Railroad Commission defenses" are flawed because:

1. The well operators, not the Texas Railroad Commission, classified the wells,

2. The Producer Group operators' oil well classifications are based on fraud,

3. The Producer Group operators' classification of most of their gas production as casinghead gas is doubly fraudulent, and

4. The Producer Group operators' well classification filings, proration unit filings and NGPA well eligibility filings omitted material facts and are therefore void.

The Producer Group's answer contends that the information sought is not relevant because:

1. This Commission has held in abeyance Docket No. GP84-8-000 which concerned whether conversion of a portion of gas production into liquids amounted to an unlawful diversion of natural gas.

2. The Commission's Office of Enforcement, in a Prehearing Conference Memorandum, March 6, 1984, at page 9 states that:

> Also not in issue in this proceeding are the acts and practices of certain respondents involving the use of refrigeration units to extract natural gas liquids ("NGLs") from the gas produced by their oil wells. The question of the propriety of the counting of the extracted NGLs as crude oil for purposes of computing Gas-Oil Ratios is the subject of a proceeding presently pending before the TRC. Very simply, these acts and practices are not material to the existence of the violations of federal law alleged in the Show Cause Order, although they may significantly affect the magnitude of these alleged violations and may prove to be of interest in this proceeding.

3. The Commission's Show Cause Order, 26 FERC ¶ 61,207, footnote 3, states: "The question of title to casinghead gas is being litigated in Texas state court, and not in issue in this proceeding." Enforcement Staff's Prehearing Conference Memorandum noted this fact and commented that resolution of that state court action can not be dispositive of the allegations of violations of federal law contained in the Show Cause order.

4. Anadarko and Pan Eastern's requests are duplicative of Enforcement Staff's discovery requests.

Findings

The motion to compel is denied in major part for several reasons. First, several requests for admissions, for

example number 8, and interrogatories, for example number 24, appear argumentative. Second, I am not prepared at this point to rule on the interaction of state and federal law on the issue of well determinations under the NGPA. However I definitely do not intend for this proceeding to duplicate the litigation before the Texas Railroad Commission in *Application of Phillips Petroleum Co., et al.*, Docket No. 10-77, 314 on the legality of counting extracted natural gas liquids as crude oil in calculating gas-oil ratios. I note that Movants were parties to the state proceeding and have already engaged in discovery on the same issue, and Staff's view that the allegations concerning use of refrigeration units are not material to whether the violations alleged in the show cause order exist. The Producer Group need not answer duplicative discovery requests and Movants have failed to show that their requests are not duplicative.

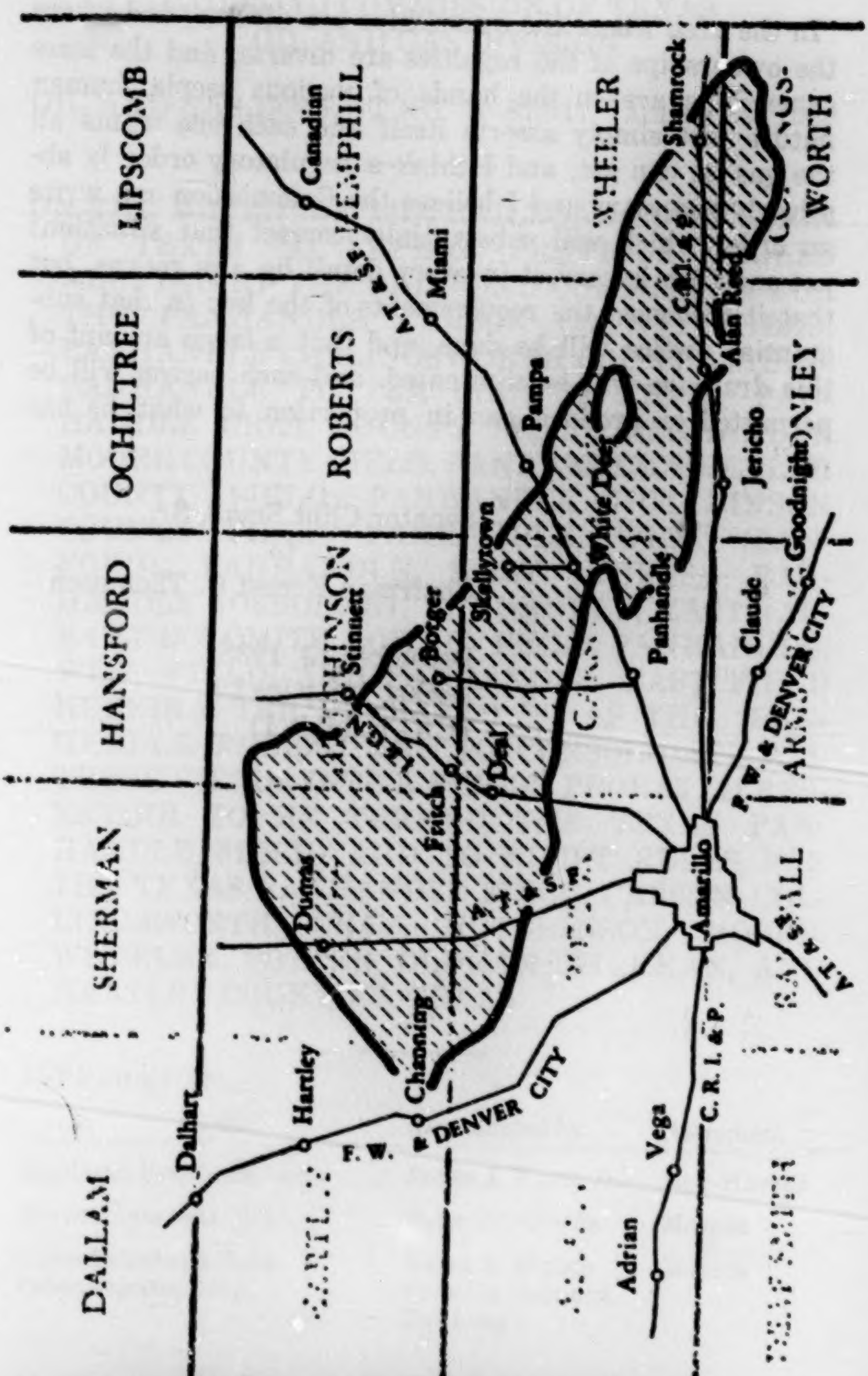
I find the Producer Group's objection to answering admission number 6 invalid. The question of whether the Producer Group claims to "own rights to produce natural gas from those wells on the subject property that are classified as gas wells" is basic and it should make its position known. The *title* to casinghead gas which is pending before state courts is a different and distinct issue. For this reason the Producer Group should answer request for admission no. 6.

APPENDIX G

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DOCKET NO. 10-87,017

PROPOSAL FOR DECISION

ON THE MOTION OF THE RAILROAD COMMISSION OF TEXAS TO REPEAL PREVIOUS ORDERS ADOPTED BY THE RAILROAD COMMISSION FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELD, PANHANDLE, WEST FIELD, AND PANHANDLE, EAST FIELD HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS" AND TO CONSOLIDATE ALL THESE FIELDS INTO A SINGLE PRORATED RESERVOIR TO BE TERMED THE TEXAS PANHANDLE FIELD; AND TO ADOPT RULES FOR THE TEXAS PANHANDLE FIELD, CARSON, COLLINGSWORTH, GRAY, HUTCHINSON, MOORE, WHEELER, POTTER, OLDHAM, SHERMAN, AND HARTLEY COUNTIES, TEXAS



LIPSCOMB
OCHILTREE
HANSFORD
SHERMAN
DALLAM
ROBERTS
WHEELER
WORTH
Canadian
Miami
Pampa
Skellytown
White Deer
Panhandle
Shamrock
Alan Reed
Jericho
Goodnight
Claude
Stinnett
Borger
Fritch
Deal
Dumas
Channing
Hartley
Dalhart
Amarillo
Vega
Adrian
A. T. & S. F.
C. R. I. & P.
F. W. & DENVER CITY

"In the area where the ownerships are diverse, and where the ownerships of the royalties are diverse, and the lease ownerships are in the hands of various people, human nature just simply asserts itself and each one wants all the gas he can get, and I think a regulatory order is absolutely necessary and I believe the Commission can write an order which will substantially correct that situation; not one that is correct in every detail by any means, but that it will meet the requirements of the law in that substantial justice will be done, and that a large amount of this drainage will be eliminated, and each person will be permitted to produce gas in proportion to what he has . . ."

—Senator Clint Small, Sr.
to
Chairman Ernest O. Thompson

December 13, 1938
Docket 108 page 29
(CIG Exhibit 1)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 10-87,017 March 21, 1988

ON THE MOTION OF THE RAILROAD COMMISSION OF TEXAS TO REPEAL PREVIOUS ORDERS ADOPTED BY THE RAILROAD COMMISSION FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELD, PANHANDLE, WEST FIELD, AND PANHANDLE, EAST FIELD HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS" AND TO CONSOLIDATE ALL THESE FIELDS INTO A SINGLE PRORATED RESERVOIR TO BE TERMED THE TEXAS PANHANDLE FIELD; AND TO ADOPT RULES FOR THE TEXAS PANHANDLE FIELD, CARSON, COLLINGSWORTH, GRAY, HUTCHINSON, MOORE, WHEELER, POTTER, OLDHAM, SHERMAN, AND HARTLEY COUNTIES, TEXAS

APPEARANCES:

Party	Represented by	Alignment
Anadarko Petroleum Corp.	James J. Ward, Jr.	Non-Movant
Burnett Interests/T.C.U.	Robert C. Grable	Movant
Cabot Petroleum Corp. Cabot Pipeline Corp.	Barry K. Bishop Priscilla Hubenak Pat Long	Movant

Party	Represented by	Alignment
Celeron Oil & Gas Co.	Brian Sullivan Sandra B. Buch Cynthia M. Sullivan Paul Keeler Anna Maria Marsland	Movant
Colorado Interstate Gas Co.	Patrick Thompson Pete Schenkkan	Non-Movant
Conoco, Inc.	Tom Burton	Non-Movant
Damson Oil Company Diamond Shamrock (Maxus)	John Soule Elizabeth Miller Curtis O'Rear	Non-Movant
Dyne Oil & Gas, Inc.	Lloyd Muennink	Movant
El Paso Natural Gas Co.	John F. Nance Paul Burchell (Bob Manning) (Babe Kendrick)	Non-Movant
G.N.C. Oil Company	Lloyd Muennink	Movant
H.N.G. Oil Co. (Enron)	Joe H. Foy	Movant
J. M. Huber Corp.	C. C. Small, Jr.	Non-Movant
Mesa Operating L.P.	John Soule Elizabeth Miller	Non-Movant
Mobil Producing TX & NM	Philip F. Patman	Non-Movant
Moore County Royalty Owners Association	J. R. Lovell	Movant
Natural Gas Pipeline Co. of America	Carla Doyne Rex White, Jr.	Non-Movant
North Plains Energy Corp.	Thomas C. Moore	Movant
Northern Natural Gas (Enron)	Jane G. Alseth	Movant
Panhandle Eastern Pipeline Co.	Jack Glaves	Non-Aligned
Phillips Petroleum Company	Joe Cochran Tim George	Non-Movant
Tenneco Oil Company	Elizabeth Miller John Soule	Non-Movant
Texaco, Inc.	Joe H. Foy	Movant
Williams Natural Gas Co.	J. D. Steelman, Jr. Timothy E. McCoy	Non-Aligned

Witnesses Appearing for Movants

Name	Position
William J. Murray	Petroleum Engineer, Consultant
Clarence Stumpf, Jr.	Petroleum Engineer, Consultant
C. Ronald Platt	Petroleum Engineer, Burnett Ranch
L. C. Shelton	Interested Party
Ron Slover	Interested Party
Max Banks	Operator, Baker & Taylor
Chester Lambert	Operator, Baker & Taylor
Ed Podzemny	Operator, Baker & Taylor
Marvin Slaymaker	Pipeline Manager, Cabot
Brian Schwarz	Engineer, Cabot
Frank Groce	Operator/Geologist, GNC Company
Bill Sutton	Operator/Geologist, Dyne Oil & Gas
Billy Gillman	Petroleum Engineer, Consultant
Ronny Babcock	Grandview-Hopkins I.S.D. Board Member
Charles Buzzard	Appraiser-Gray Co. Appraisal District
S. Gray Johnston	Petroleum Engineer, Moore County Royalty Owners Association
Betty Haiduk	Interested Party
J. B. Herrmann	Operator, Herrmann Oil & Gas Company
Carroll Beaman	Operator/Engineer, American Star Energy and Minerals Corporation
T. M. Hatfield	Operator/Engineer, BHI Energy
J. Donald Clark	Petroleum Engineer, Consultant
Rex Howell	Operator/Engineer, Enron Oil & Gas Co.
J. B. Watkins	Operator/Geologist, (Various Companies)
Michael Holmes	Geologist, Consultant
Rick Johnston	Petroleum Engineer, Consultant
John Drisdale	Petroleum Engineer, Consultant
Charles Tutt, Jr.	Petroleum Engineer, Consultant
Miles Reynolds, Jr.	Chemical/Petroleum Engineer, Consultant
Robert C. MacDonald	Petroleum Engineer, Consultant
Shirley R. Clark	Manager, Burnett Interests

Witnesses Appearing for Non-Movants

Name	Position
Patrick Williams	Geologist, Tenneco Oil Company
Melissa Symmonds	Petroleum Engineer, Tenneco Oil Company
Maston Powers	Petroleum Engineer, Conoco
Thomas A. Bay	Geologist, Consultant
Ron Wilson	Log Analyst, Consultant
Wayne Ahr	Geologist, Professor, Texas A&M University
James P. Johnson	Physicist, Phillips Petroleum
Richard Strickland	Petroleum Engineer, Consultant
Clark Gillespie	Petroleum Engineer, Consultant
Henry E. Brown	Attorney, CIG

Name	Position
O. G. Poling	Lease Administration, Phillips
William Paul Loyd	Division Landman, J. M. Huber Co.
Stanley Shoemaker	Land Administration, Anadarko
Dave Oyler	Property Administration, Mobil
Garland Robinson, Jr.	Consultant, Conoco
Thomas N. Burdette	Land Manager, Damson Oil
James Weldon Prichard	Lease Records, Maxus Exploration
Mark Wesley Seale	Senior Landman, Mesa Operating L.P.

PROPOSAL FOR DECISION

HEARD ON:

February 18-19, 1986 (12 hours)
March 21, 1986 (4 hours)
January 6—May 7, 1987 (327 hours)
September 9, 1987 (7 hours)

HEARD BY:

George Singletary, Senior Technical Examiner
William Osborn, Legal Examiner
Greg Cloud, Technical Examiner

STATEMENT OF THE CASE

Purpose of the Hearing

On January 9, 1986 the Commission issued its notice of hearing in this docket. The purpose and genesis of the hearing was cited as follows:

> "A staff review of the information obtained as a result of the July 8, 1985 Commission memorandum to all operators in the Panhandle Fields indicates a substantial number of oil and gas wells are downhole commingling hydrocarbon production from the top of the Panhandle Lime to the bottom of the Granite Wash formation including the Brown Dolomite, White Dolomite, Arkosic Dolomite, Moore County Lime, and Arkosic Lime Formations.

While these formations originally may have been separate and distinct accumulations of oil and gas, the information indicates they are now in communication because of completion practices throughout these formations. So that the oil and gas hydrocarbon production from these various Panhandle formations can be effectively developed and produced to prevent waste, promote conservation, and protect correlative rights, this hearing is called and the Commission will consider consolidating all the Panhandle Fields into one, the proposed "Texas Panhandle Field", and prorating this consolidated new field as an associated reservoir.

(Hearing notice, Oil and Gas Docket No. 10-87,017, pages 1 and 2).

The notice was served on all operators in the field and generated a considerable response, resulting in designation of some 56 persons or companies as parties and an additional 50 as "interested persons".

Identification of Parties

The parties generally aligned as "movants" (supporting changes in field rules and repeal of previous orders as outlined in the hearing notice) or "non-movants" (opposing changes in the field rules). Movants include the Burnett Ranch Interests (Anne Burnett Windfohr, Texas Christian University, and Burnett Oil Co., Inc.), Cabot Petroleum Corp., Cabot Pipeline Corp., Celeron Oil and Gas Company, Dyne Oil and Gas, Inc., Enron Oil and Gas Company, G.N.C. Oil Company, H.N.G. Oil Company, Moore County Royalty Owners Association and Texaco, Inc. In addition, some operators in the field filed appearances and gave testimony in support of movants. These included Baker & Taylor Drilling Company, Herrmann Oil and Gas Company, American Star Energy and Minerals Corporation, BHI Energy, and J. B. Watkins.

Non-movants include Colorado Interstate Gas Co. (C.I.G.), Conoco, Inc., Damson Oil Co., Maxus (formerly Diamond Shamrock), El Paso Natural Gas Co., J. M. Huber Corp., Mesa Operating Limited Partnership, Mobil Producing Texas & New Mexico, Inc., Natural Gas Pipeline Co. of America, Phillips Petroleum Company, and Tenneco Oil Company. Panhandle Eastern Pipeline Co. and Williams Natural Gas Co. styled themselves as "nonaligned" but generally aligned with the non-movants.

Those of the movants who are operators principally have oil wells, and movants were often referred to in the hearing as the "oil operators" for this reason or because they sought field rules favorable to oil production. Non-movants were accordingly styled "gas operators", but the evidence showed that this was not an accurate label. The non-movants are among the largest Panhandle oil operators with Phillips, J. M. Huber, Tenneco and Mobil Producing Texas & New Mexico, Inc. among the top 10 oil producers in the field. Only one of the "oil" operators/ parties made this list. (Gillespie Exhibit 63F, see appendix 3). The "gas" operators have tremendous amounts of oil acreage in the field also. The examiners propose that if generalization is necessary, it is more accurate to style movants as the "new operators" and non-movants as the "old operators". Each side has one or two parties which do not match these designations but have aligned with them anyway.

Size of Field

The gas discovery well in the Panhandle Field was drilled by Canadian River Gas Company in 1917, and the oil discovery well was drilled by Gulf Production Company in 1921. The field is 1.76 million acres in size, with 10.796 oil wells and 3.510 gas wells producing in June of 1986. (Tr. 8676, Johnston Exhibits 5 and 11). The average oil well now makes approximately 2 barrels of oil and 16 mcf of casinghead gas per day, and average

gas well makes about 114 mcf/day. (Tr. 5195, 8967, 8430 line 1, see 5235 line 20 estimating average of 114 mcfd, Johnston Exhibit 11). Cumulative production to mid-1986 is estimated at 1.24 billion barrels of oil, 32 trillion cubic feet of gas well gas and 6.4 trillion cubic feet of casinghead gas. (Gillespie Exhibits 5 and 10, Tr. 6424-6425, Johnston exhibit 3) Remaining reserves are estimated by non-movants at approximately 100 million barrels of oil and 2.8 trillion cubic feet of gas well gas. (Gillespie Exhibits 5 and 10). Movants estimated that remaining oil reserves were substantially higher and provided several estimates based on various types of calculations. The most conservative estimate (of oil recoverable from the traditional gas area) was 400 million barrels of oil. (Tr. 6330). The reservoir on discovery had a uniform pressure of about 435 pounds, which is subnormal for depth. This field is now in an advanced stage of depletion, with current pressures ranging from 0 to about 50 pounds. The producing mechanism is primarily dissolved gas drive, in contrast with the other large field in the state, East Texas, which is primarily water drive.

Area of Development

The vast majority of oil wells are located along the northeast rim of the field, referred to at times as the "traditional" oil area. The remainder of the field has historically been considered to be productive primarily of dry gas (the "traditional dry gas area"), but some recent developments, especially in Moore County, are proving that there is oil in this part of the field also. The Moore County oil play is not prolific; the average well there makes only 4 barrels per day, but this is double the field-wide average. (Johnston Exhibit 16). The producing GOR of these wells, which averaged 22,432:1 in 1986, is fairly high.

Recent oil completions in other counties have proved less successful; Hutchinson County, for example, had over

1100 new oil completions in the last ten years but the 1986 average oil rate was one barrel per day. (Johnston Exhibits 20, 23).

Although the statistics are clouded by the presence of LTX liquids which were reported as oil in the late 1970s and early 1980s, it is clear that recent oil development in the traditional gas area of the field has to some degree tended to arrest the natural fieldwide oil decline rate. (Johnston Exhibits 10A, 13). In particular, drilling and new oil completions between 1978 and 1985 seem to have arrested a 20 year decline in the oil rate, with calculated incremental oil recovery to date of about 23 million barrels and future increment projected at 41 million barrels by Rick Johnston, Petroleum Engineer for movants. (Johnston Exhibit 2, Tr. 5129 line 23, 5176). Some increment is apparent regardless of controversy over the use of exponential vs. hyperbolic decline curves. (Tr. 5309-5310). Calculation methodology can vary the numbers substantially, and some of Mr. Johnston's numbers are optimistic, but his conclusion that known oil reserves have increased due to new drilling is correct. (Tr. 5352-5353, 5370).

The new operators seek field rules which would encourage further exploration in Moore County and elsewhere. The old operators are satisfied with the current rules, and it cannot be said that they have no interest in exploration for oil—Phillips Petroleum, for example, claims over 170,000 acres of oil rights in Moore County alone. (Poling Exhibit 1)

REGULATORY HISTORY

Problems in the 1930s

Following completion of the discovery well in 1918 it was rapidly apparent that a tremendous field extended across the Panhandle. By the early 1930s, operators in the field faced a problem identical to that of their coun-

terparts in the East Texas Field: lack of a market for their product. As a result, a number of wasteful practices arose in the Panhandle, foremost of which was the operation of gasoline stripping plants. These plants took advantage of a physical property of natural gas to condense on compression and form a clear liquid condensate which was useable in its raw state as automobile fuel. This condensate was referred to as "natural gasoline" and following its removal some 90% of the original gas volume remained as a dry residue gas of no value, and was flared. Enormous quantities of natural gas were required to manufacture natural gasoline in this manner due to the inefficient conversion ratio. Because of the poor conversion ratio gasoline plants paid a very low price for their feedstock. Roy White, an engineer with the Texas Company, testified in a 1932 Commission hearing that the gasoline plants were then paying only 1/10 of a cent per mcf vs. 3½ cents per mcf being paid for the quantities of gas which could be transported by then existing pipelines. (Hearing of September 1, 1932, p. 47, CIG Exhibit 1)

The only other market for natural gas was for use in manufacturing carbon black, but demand was limited. In 1933 there were 25 carbon black plants in operation and they produced 71% of the total output in the entire United States, the vast majority of which was used to manufacture rubber. (Gillespie Ex. 50). Like gasoline stripping plants, the first carbon black plants used wastefully inefficient conversion methods and consumed tremendous quantities of gas in the manufacturing process.

Unencumbered by comprehensive field rules, operators were producing as much as they were technically able. In a November 1935 hearing, H. M. Stallcup, vice-president of Skelly Oil Company, described these practices:

> With the advent of intensive development in the Borger area, and the fact that a great majority of

the oil wells produced large volumes of gas accompanying the oil, there were started several large natural gasoline plants, or they are often referred to as casinghead gasoline plants. Some of these large volumes of gas accompanying the oil at that time, and for subsequent years, was literally and accurately described as casinghead gas, that is gas accompanying the oil from the oil reservoir, inevitably and unavoidably produced with the oil. Additionally, as gasoline plants were constructed, and particularly in the latter part of 1926, and in the early part of 1927, when the first carbon black plants were built in the field, thus making the first and only considerable market for such residue gas from these plants, the operators of oil wells started what is to me the vicious practices of either improperly completing the oil wells in the first instance, or by ripping and shooting or in any other matter that might occur to them, manhandling such properly completed wells so as that they not only produced their oil but almost unbelievable quantities of gas from the upper gas horizons. This afforded tremendous casinghead residue gas, and this, to me illegitimate, gas from the upper horizons was made available for any markets that might be obtained, and the only one to date, with very few exceptions, that has developed has been for the manufacturing of carbon black. Those gasoline plants continued to increase in number throughout the area as the area was developed, to the extent that at the present time there are 41 gasoline plants of one type and another constructed and operating throughout the field. Similarly there have continued to be constructed and operated carbon black plants to the extent of approximately 25 at the present time.

(Hearing of November 19, 1935, p. 130-131, CIG Exhibit 1)

By June of 1934, the Commission's Pampa office reported that residue gas was being vented or flared into the atmosphere at the rate of some 1 *billion* cubic feet per day. At that time it was the largest gas field in the world. (Gillespie Exhibit 50, page 9). Emby Kaye, a Skelly Oil Company vice-president, condemned these practices in a 1934 "Petroleum Engineer" article:

> "But if this (pre-1933) East Texas Gasoline is an unwanted child, born of wedlock, the new natural gasoline brought into production in 1933 and to this writing, in the Texas Panhandle is a child *born of rape.* If the former had to be produced as a conservation matter, the latter is the result of the very negation of conservation. The wanton waste of billions of cubic feet of natural gas for the extraction of the pittance yielded from the gasoline can never be excused, except as selfishness and greed."
>
> (Gillespie exhibit 50, p. 17, emphasis supplied)

A committee of engineers representing the major gas operators in the field published a report on gas wastage in 1934, wherein they asserted:

> "It is common knowledge that it has long been the practice of many operators to rip casing which formerly shut off the big gas pay, in order to permit the production of excessive volumes of gas with the oil."
>
> (Gillespie Exhibit 50 page 14)

This was acknowledged earlier by Roy White, the Texas Company (Texaco) engineer, who testified to the Commission in 1932 that as much as 70% of the "casinghead gas" was "coming from the upper formation, in what we call the dry gas reservoir" and stated his belief that such high quantities of gas were produced "through improper completion, either intentional or otherwise, or perhaps through intentional ripping of the casing." (Oil and Gas

Docket No. 64, pp. 41, 57, September 1, 1932, CIG Exhibit 1).

Legislative Reactions in the 1930s

In response to problems in the Panhandle and wasteful practices elsewhere in the state the Texas Legislature passed a comprehensive conservation statute known as House Bill 266 on May 1, 1935. The act provided in relevant part:

Section 1. Declaration of Policy:

> In recognition of past, present, and imminent evils occurring in the production and use of natural gas, as a result of waste in the production and use thereof in the absence of correlative opportunities of owners of gas in a common reservoir to produce and use the same, this law is enacted for the protection of public and private interests against such evils by prohibiting waste and compelling ratable production.

* * *

Section 3. The production, transportation, or use of natural gas in such manner, in such amount, or under such conditions as to constitute waste is hereby declared to be unlawful and is prohibited. The term "waste" among other things shall specifically include:

(a) The operation of any oil well, or wells with an inefficient gas-oil ratio.
[now Tex. Nat. Res. Code § 86.012(a)(1)]

* * *

(l) The production of natural gas from a well producing oil from a stratum other than that in which the oil is found, unless such gas is produced in a separate string of casing from that in which the oil is produced.
[now Tex. Nat. Res. Code § 86.012(a)(11)]

* * *

Section 4.

(b) No person in possession of or operating any oil well shall produce from such well natural gas found in a horizon productive of natural gas only.

[now Tex. Nat. Res. Code. § 86.097]

* * *

Section 22.

The Commission shall be vested with a broad discretion in administering this law, and to that end shall be authorized to adopt any and all rules, regulations or orders which it finds are necessary to effectuate the provisions and purposes of said law.

(Act of May 1, 1935, Ch. 120, 1935 Tex. Gen. and Spec. Laws 318)

Celeron et. al. correctly note that the bill "does not contain any reference to perforations of gas-oil contact", commenting that "the gas operators merely infer the presence of such language." In the opinion of counsel for Celeron, "the purpose of the bill was not to impose restrictions on perforations in oil wells relative to a gas-oil contact, but . . . to prevent waste." (Celeron Reply to Closing Statements, p. 30). The examiners respectfully disagree with the Celeron position, and submit that the purpose of the bill was to prevent waste of every type then common in the field, including among others the commonly known problem of high performations discussed by Mr. White, Mr. Stallcup, and the 1934 Engineering Committee. Section 4(b) of the bill, now § 86.097 of the Natural Resources Code, was part of a special amendment sponsored by Amarillo Senator Clint Small, Sr. (1935 Senate Journal, p. 1229). The Senator recognized the existence of a "horizon productive of natural gas only".

Commission Action On House Bill 266

Following the pasage of H.B. 266, the Commission commenced investigations and convened hearings to consider rules for the Panhandle Fields. Since one provision of the act defined waste as operation of a well at an inefficient gas-oil ratio, Commission engineers conducted a survey of ratios in the field and reported in July of 1935 that oil wells in the field with gas-oil ratios between 0 and 5000:1 produced 92.6% of the oil, a figure which rose to 98.2% if the cut-off was raised to 25,000:1. (Hearing of July 18, 1935, p. 72, CIG Exhibit 1). At that hearing, Commission Chief Engineer Griffin testified that the proper way to complete an oil well in the field so as to minimize producing GOR was to set the oil string "into the producing formation. In other words, *below the contact of the oil and gas.*" (Hearing of July 18, 1935, p. 85, CIG Exhibit 1, emphasis supplied).

After receipt of further evidence and testimony that summer and fall, the Commission issued a comprehensive, 12 page order on December 10, 1935 establishing rules for the Panhandle Fields. The contemporary understanding of the meaning and purpose of H.B. 266 is evident from the requirements set forth in the order, which is excerpted in pertinent part as follows:

> WHEREAS, In conformity to House Bill No. 266 . . . the Commission has held public hearings . . . and from intensive and comprehensive study of this field . . . the Commission finds:
>
> * * *
>
> The Oil and Gas so far encountered in the Panhandle field has been found, with minor exceptions, in four separate strata, namely: the dolmite (sic), the arkosic-dolmite (sic), the gray limestone, and the granite wash. These four formations overlie one another and though they are normally separated one from another by impervious strata, they are interconnected as is shown by the fact that the virgin

pressure of oil and gas from all of them was 430 pounds per square inch at sea level, regardless of the location in the field.

* * *

The oil wells in the oil pools in the field were, as a general rule, drilled through one or more gas-containing strata before entering the oil-containing stratum, and, in many instances, the wells were so completed as to cause production of gas from the gas strata along with the oil and gas from the oil stratum, with the result that tremendous quantities of gas have been produced with the oil, large portions of its coming from gas-producing strata above the oil-producing strata. This gas was in large part blown into the air, and it has been estimated that in excess of two trillion cubic feet of gas produced in this manner has been wasted into the air.

* * *

From testimony adduced at hearings and from a study by its Engineering staff, the Commission finds that . . . after the distillation of the organic materials into oil and gas, the water, oil and gas segregated in porous strata started arranging themselves in accordance with their densities; that due to the buoyant force caused by the different specific gravities of water, oil and gas, the lighter oil and gas migrated upward in the water contained porous strata, interbedded between impervious strata.

* * *

IT IS ORDERED, That no gas well or oil well shall be permitted to produce gas from different levels, sands or strata at the same time through the same string of casing, and that if the Commission believes this to be happening in any case, the Deputy Supervisor is hereby authorized to make gas-oil ratio, bottom-hole pressure, charcoal test of the gas for its gasoline content, specific gravity determination of

the gas, analysis of the gas, a study of the well log, and any other tests at any time for the purpose of comparing the gas with gas from offset property, or tests pertinent to the information desired, and the owner of such well is hereby directed to do all things that may be required of him by the Commission's Agent to properly make such test.

* * *

IT IS FURTHER ORDERED, That this docket be kept open for the introduction of further evidence or information so that the Commission may, at any time modify or amend this order or enter such other or further general or special order or orders as may be necessary to correct or relieve any inequalities, injustices or inequities that may result from the enforcement of the provisions of this order.

(December 10, 1935 Order, CIG Exhibit 6)

Commission Posture 1935-1985

Commission employees have had occasion to make a number of public statements about the Panhandle Fields over the years. A few of these are excerpted:

1936 A.M. Crowell, Natural Gas Engineer:

"The question of gas/oil ratio in the Panhandle Field is a tremendous one. Many wells drilled in the oil areas of the Panhandle Field have been improperly completed and in some cases it has been found that the inside string of casing has been perforated, causing large amounts of gas to be produced with the oil. These high gas/oil ratio wells produce a small per cent of the total oil produced in the Panhandle Field but by their operations and production of large amounts of gas are depleting the field of its reservoir energy, causing low pressure areas and bringing about a condition where a large amount of oil will never be recov-

ered which could be recovered if all the wells were operated on an efficient gas/oil ratio."

(CIG Exhibit 4, page 5)

1937 V. E. Cottingham, Director of Production:

"Another thing that causes high gas-oil ratios in the Panhandle Field is the way the wells have been completed; they drill down through a gas horizon on into another horizon, an oil horizon, and possibly that is one of the chief reasons for high gas-oil ratios in the Panhandle Field, and that condition was brought about, of course, in the early days, the early history of the field, because gas had no market value and they sought to get as much gas coming with that oil and just let your gas and oil blow.

I am saying that a large part of the gas produced in the Panhandle—the difference between the casinghead gas and dry gas in the Panhandle is largely one of definition. In other words, a great deal of it comes from a strata above the oil produced in those oil wells that were drilled prior to any proration or any regulation with reference to containing the gas, oil and water to the original strata."

(CIG Exhibit 1, April 13, 1937, pp. 64-65, 116)

1948 Ernest O. Thompson, Chairman (and former mayor of Amarillo):

"If there is any field that we know the data on in the state of Texas, it is this field. We have had hearings and hearings and hearings. I think we have more complete data on the Panhandle Field than any field in the country, unless it is East Texas."

(CIG Exhibit 1, May 13, 1948, p. 184)

1956 J. G. McClintock, Deputy Supervisor:

"MEMORANDUM TO ALL OPERATORS OF OIL WELLS IN ALL FIELDS IN THE PANHANDLE OF TEXAS, DISTRICT #10"

"It has been brought to the Commission's attention that a few operators in this district have perforated the casing in the dry gas zone and are reportedly selling such as casinghead gas. Please be advised that in the future any violation of this nature will be dealt with accordingly, as it is definitely in violation of the rules and regulations of the Railroad Commission of Texas, Oil and Gas Division."

(Murray Cross-Examination Exhibit 1)

1977 J. C. Herring, Senior Staff Engineer:

"In reviewing both the rules for the Panhandle Fields as well as the Statewide rules, it appears that it is the intent of the Commission that oil wells in the various Panhandle Fields should be produced from below the gas-oil contact and with the lowest gas-oil ratio possible. In reviewing the production reports filed in the various Panhandle Fields and the numerous tests conducted by Commission personnel, it appears that there are a number of oil wells in the Panhandle Fields with perforations above the gas-oil contact which are currently producing gas through the tubing-casing annulus directly to a sales outlet. It appears that these oil wells are not only in violation of the Commission's intent as previously stated, but also in violation of the Commission Rules."

(Memorandum to Phillip Russell, Director of Field Operations. Released to Panhandle Fields operator Wallace Bruce in 1982. Murray Cross-Examination Exhibit 2)

1985 Jim Morrow, Director, Oil and Gas Division:

"TO ALL OPERATORS IN THE PANHANDLE FIELDS"

"It has come to the attention of the Commission that many wells have been completed in the Panhandle Fields in a manner which does not comply with current field rules.

* * *

Completing an oil well or working over an oil well so that any portion of the producing interval is above the gas-oil contact may not be consistent with the (cited) orders, rules and statutes. Likewise, completing a gas well or working over a gas well so that any portion of the producing interval is below the gas-oil contact may not be consistent with the (cited) orders, rules and statutes." (Citing Rule 3 of Oil and Gas Circular 16-B, amended, Special Order Nos. 10-316 and 10-3087, Statewide Rules 10 and 13 and Texas Natural Resources Code §§ 86.012 and § 86.097.)

(Official notice, Hearing Notice X, page 8)

LTX Proceedings

In the fall of 1983, the Commission held a 30 day hearing in Docket No. 10-77,314 to consider whether liquids produced from low temperature extraction (LTX) units in the Panhandle fields could be counted as oil for well classification purposes. Some 1000 of these machines were placed in service between 1977 and 1983. (Tr. 5191). On May 13, 1985 the Commissioners signed an order finding that the product of LTX units was not crude oil in the statutory sense, and that to classify wells based on a calculation counting these products as crude oil would be contrary to the statutory definition of an oil well.

The Commission order of May 13th required that all LTX wells be retested within 75 days. Many units were

apparently taken out of service immediately as only 515 wells were submitted for testing—251 passed, 71 failed and the remainder were inconclusive or "unacceptable tests" for various reasons. (Tr. 5178, 5180). The use of these machines was not prohibited, but it is forbidden to count their product as crude oil for well classification purposes.

FERC Actions

In February of 1984 the Federal Energy Regulatory Commission (FERC) commenced its own investigation of the high perforation problem, ordering 37 oil well operators (Respondents) in the Panhandle Fields to show cause why they had not violated various sections of the Natural Gas Act (NGA) and Natural Gas Policy Act of 1978 (NGPA). Of primary concern were alleged violations of NGPA § 504, which effects a ceiling price (§ 104 price) for gas dedicated to interstate commerce before enactment of the statute (before November 8, 1978). In 1984, Dorchester Natural Gas Company operated some 35 gas wells in the area of investigation. These were open hole Brown Dolomite wells completed between 1933 and 1949 on some 21,000 acres in Carson and Gray Counties (subject acreage). Between 1978 and 1984, Respondents completed some 196 "oil" wells on the subject acreage and qualified all of their "casinghead gas" for NGPA § 103 or § 109 prices for "new" gas (substantially higher prices permitted for new than for old gas, this in order to encourage exploration for new gas reserves as a policy objective of the NGPA). FERC convened a hearing to determine whether Respondent's "casinghead gas" was in fact being produced from a dry gas zone already producing through Dorchester wells, thus dedicated § 103 gas.

Twenty-eight of the Respondents were operating LTX units on their leases, and based on facts arising during the hearing the FERC judge determined that "In most cases Respondents' W-2 forms filed with the Railroad

Commission do not show the perforations in the Brown Dolomite made after initial completion in the Granite Wash." (Docket GP84-23-000, 30 FERC 63,017 at 65,030). Based on ASTM-86 distillation tests, recombination analysis and phase diagram comparison, specific gravity analysis, gas-oil ratio analysis, and geological evidence, the administrative judge concluded that:

> "most of the gas produced by most of the Respondents is not casinghead gas because it is not gas indigenous to an oil stratum and produced from that stratum with oil, and that most of the respondents are producing gas which would otherwise be produced by Dorchester." *Id.* at 65,048.

The judge interpreted Railroad Commission field rules in making this determination, which she based on a gas-oil contact theory.

> "Since the Railroad Commission has established a division of the reservoir so that the Panhandle West Gas Field is that portion of the reservoir lying above the gas-oil contact, it follows that Dorchester's proration unit is that portion of the reservoir above the gas-oil contact which lies beneath each 640 acre unit assigned to a Dorchester well. Perforations in the Brown Dolomite by themselves are not conclusive evidence that respondents are producing and selling [§ 104 dedicated, or "old" gas]. . . What is determinative is whether or not respondents' gas production comes from above the gas-oil contact because this would mean that such production was not casinghead gas. . . . *The location of the gas-oil contact is determined in each individual wellbore and may vary from one well to another.* (emphasis supplied) *Id.* at 65,048.

Counsel for movant operators in this Railroad Commission proceeding have asserted that Judge Murray did not correctly interpret the Panhandle Field rules.

As in the instant proceeding, respondent operators in the FERC hearing submitted evidence of high oil in the Brown Dolomite, on which the Judge commented:

> "It is obvious from the record that it is not unusual, for example, to find shows of oil in cores and various kinds of rock samples but these isolated bits of visual evidence are unreliable indicators of whether crude oil will be produced at all, or in any meaningful quantities. (*Id.* at 65,048).

The Judge commented that FERC enforcement staff viewed this case

> "as revealing only the tip of the iceberg of a widespread practice where parties, under the guise of drilling new oil wells, transform old (relatively cheap) dedicated natural gas into new (high cost) undedicated gas. (*Id.* at 65,035).

All respondents were eventually ordered to cease violations of various provisions of the NGPA. In this hearing we looked at the rest of the "iceberg".

CHANGED CONDITIONS

The Biblical "threescore and ten years" have passed since discovery of the Panhandle field, and the passage of time has seen two generations of operators come and go. Comprehensive field rules were passed in 1935 to curb the abuses of the first generation, but by 1956 a second generation had to be reminded of the perforation commandment. Celeron has glossed over the 1956 edict of Mr. McClintock to all operators in the field that high perforations were "definitely in violation" of Railroad Commission rules. They have only one comment about the memorandum in all of their filings, that "There is no evidence in the record of any inspections or imposition of penalties resulting from Mr. McClintock's statement." (Celeron Reply, p. 35). The examiners respectfully submit that this is not accurate. In fact, due to

fieldwide investigation at the time, some 70 wells were reclassified from oil to statutory gas wells (Oil and Gas Docket 108, #10-37,495, Hearing of May 7, 1958, p. 19 lines 1-4, p. 20 line 14, CIG Exhibit 3).

We now face the influx of a relatively new group of operators, Like their predecessors in some ways, but different in others, they are pushing the field rules to the limit and have requested that the Commission "clarify" them. These limits have been clouded in recent years, perhaps not so much by operator agression but by advances in wellbore completion technology which permit the production of some oil from zones formerly thought productive of dry gas only.

There have been substantial advances in wellbore completion technology since 1935 which may qualify as "changed conditions" under the doctrine set forth in *Railroad Commission v. Aluminum Company of America*, 380 S.W.2d 599 (Tex. 1964). (See appendix 6). According to J. B. Watkins, operator, and as discussed in early Commission Docket 108 hearings in the 1920s and 1930s, the first completion method of choice was explosion of nitroglycerine to fracture the formation. (Tr. 3917-3919). Operators began to experiment with acid treatment in the mid-1930s. (CIG Exhibit 1, May 11, 1936, p. 259; Gillespie Exhibit 27). Although earlier references appear, Henry Rogatz did not attribute significance to hydraulic fracturing (gelled water, sandpropping, etc.) until 1954 (Bay Cross-Examination Exhibit 20). This type of formation stimulation is widely used today.

Early operators encountered substantial problems with wax and paraffin, as discussed in 1928 by E. J. McKee, Phillips Petroleum Co. Chief Production Engineer:

> "All the waxes encountered are to a great extent chemically inert and to date we have been unable to find any chemical that will react with them. The only thing that has any apparent effect is heat."
>
> (Bay Cross-Examination Exhibit 6, Original page 283)

Such chemicals now exist and are used routinely in the field. For example, a 1976 workover on the NGPL No. 4-T Texas Company fee well included treatment for paraffin with a mixture of kerosene and "compound C" (Bay Cross-examination Exhibit 20). Baker & Taylor makes a practice of flushing its new wells with a 2% KCL solution to minimize paraffin problems. (Podzemny Exhibit 1).

Modern day operators have access to electric wireline log technology unavailable in the 1920s and 1930s. A wide variety of tools are now available to precisely measure formation density, porosity, and permeability, water and hydrocarbon saturations, etc., the analysis of which has been elevated to a separate science undreamed of in the pre-nuclear age when gamma rays and neutrons were but ideas in the minds of a very few scientists. Similar advances in chromatograph and fluorescence analysis would have staggered those who completed the Canadian River Gas Company discovery well in 1917.

Former Commissioner Bill Murray testified that the impact of these technological changes was dramatic. He discussed the evolution of logging and stimulation technologies and improvements in cementing technology and concluded that the majority of wells completed today would not have been completed or produced 50 years ago. (Tr. 83). Medford McCoy, a Conoco Engineer, studied the field in 1953 and reported that in the gas area, "Wells which have been drilled deep enough to reach the gas-oil contact were drilled for oil, but the density of the formations at this level was prohibitive to production in most cases." (Powers Exhibit 3 page 7) The examiners agree with Mr. Murray's conclusion, but note that some part of the phenomena must be attributed to economics. One acknowledged expert on the field, Henry Rogatz, spoke thus on the early days:

> "Wells with initial productions below 250 barrels were disappointing and almost uncommercial unless

their daily capacity could be increased. In the Depression and ten cent-a-barrel days, wells of this size often were plugged." (Bay Cross-examination Exhibit 25, page 29)

The examiners submit that dramatic advances in wellbore completion technology since 1935 satisfy the "changed conditions" doctrine set out in *Aluminum Company of America*, supra, and that these changes will support a revision of the field rules.

RESERVOIR THEORIES

Movants and non-movants in this proceeding differed in their theories of reservoir mechanics and producibility of remaining reserves. Experts for movants submitted that substantial quanities of producible oil remain to be recovered from levels high in the formation, areas historically thought productive for the most part of dry gas only. Experts for non-movants disputed this assertion and took the position that while there might be residual oil high in the gas cap portion of the field, it is generally immobile to flow and not producible to the surface on primary recovery.

Movants' Theory

The principle witnesses on fieldwide reservoir theory for the movants were Dr. Michael Holmes, geologist, and Dr. Robert MacDonald, Petroleum Engineer.

Geology

Holmes Exhibit 3 depicts the structural geology of the field, overlying and generally aligned with the Amarillo uplift, which is bounded on the north by the Anadarko basin and the south by the Palo Duro basin. The field is generally productive of hydrocarbons over a 1000 foot interval which various but ranges most often between —100 feet and +900 feet subsea depth, being composed of several discrete and usually identifiable formations, including the basal fractured granite, Granite Wash,

Arkosic Dolomite, Moore County Lime, White/Brown Dolomite, and Panhandle Lime (top seal). Dr. Holmes was of the opinion that the reservoir was originally full to the top with oil at 1500 pounds, and that the gas we see in the field today was liberated from this oil due to a pressure decline of over 1000 pounds before discovery. (Tr. 4064). The Granite Wash, a clastic deposit, displays radical variations in thickness and is not present at all in some areas of the field. The White and Brown Dolomites, subsequent carbonate depositions, are according to Dr. Holmes heterogeneous and not subject to easy categorization as far as permeabilities and porosities. He testified that it was "a completely different geologic framework than the Red Cave," a higher formation which was the subject of recent Commission action in docket 10-86,552. (Tr. 4994 lines 24-25). Dr. Holmes and his support staff put together a computer database of all W-2 completion information available from the Commission, Dwight's Energy Data, Geomap Company and Petroleum Information Company. This database was the source of many of their maps and cross-sections.

Dr. Holmes postulated a fracture-matrix theory of the Brown Dolomite which was the subject of much controversy. Simply put, he believes that gravity segregation of oil and gas in the reservoir was inefficient, such that substantial amounts of "high oil" remain to be recovered, either from catchment basins or fractures intersecting capillary trapped oil.

Catchment Basins

Dr. Holmes believes that within the Brown Dolomite there are perched basinal traps full to the spill point with oil. (Tr. 4698 line 2). The permeability barriers which prevent downward migration of oil were thought to be either anhydrite or carbonate mud flat seals. (Tr. 4626). Holmes Exhibit 51 (corrected 53A) shows the location of a few high oil plays which Dr. Holmes attributed to this phenomena.

Capillary Trapping

Dr. Holmes was of the opinion that capillary forces had trapped a tremendous amount of oil high in the Brown Dolomite, primarily within the dolomite matrix. He believes that the dolomite is ubiquitously fractured, and if these fractures are intercepted by a wellbore or wellbore stimulation and sufficient flowthrough of gas is permitted, the matrix oil can be produced. Dr. Holmes' conclusion was based substantially on his examination of cores from the Celeron 16-12P well in Potter County and the Baker & Taylor 8-209 well in Moore County. Photographs of various core sections were presented for the proposition that there was free oil high in the Brown Dolomite, with fracturing intermittent and "quite fine", but open in many places (Tr. 4121, 4126-4127, Holmes Exhibit 23A, Tr. 4149).

Engineering

Using a volumetric equation, Dr. MacDonald relied on Dr. Holmes' work and calculated oil-in-place in the "traditional dry gas area" at 85.5 billion barrels of which he thought a "very small fraction" could be recovered. (MacDonald Exhibit 39, Tr. 6359) By way of an alternative approach to calculation of this fraction, he offered a material balance equation showing that 2.5 billion barrels of oil 'might be expected to be found" in the traditional gas area. (Tr. 6232). Examiner Osborn pressed Dr. MacDonald on his calculation:

Q: "Have you done any calculations or do you have any opinion as to how much of that oil is recoverable?"

A: "I believe it's possible to recover in the neighborhood of 400 to 500 million barrels."

Q: "What is the basis for your calculation that 400 to 500 million barrels are recoverable?"

A: "It's really a judgment . . . it's an outside limit." (Tr. 6653-6654)

By way of comparison, Dr. MacDonald calculated that original oil in place in the traditional oil area was 36.4 billion barrels, and production from that area over the last 70 years represents the majority of total cumulative production fieldwide, 1.24 billion barrels by his calculation. (Tr. 6651-6652)

Non-Movants Theory

The principal witnesses on fieldwide reservoir theory for non-movants were Mr. Thomas Bay, Geologist, Dr. Wayne Ahr, Geologist, and Mr. Clark Gillespie, Petroleum Engineer.

Geology

Mr. Bay was in substantial agreement with Dr. Holmes' theory of the depositional processes which took place to form the reservoir. He disagreed with Dr. Holmes' analysis of the Brown Dolomite, finding that it was a rather uniform and predictable formation generally present as a blanket deposit, which was "completely separated. . . by shales" and "not in communication" with the underlying Arkosic Dolomite. (Tr. 7829-7830). Mr. Bay's study of the field was based primarily on cable tool drilling logs from some 10,000 wellbores. These logs report the observers' perceptions of formation lithology and hydrocarbon shows, which Mr. Bay deemed accurate for the purposes of estimating distributions of oil and gas. This assumption, central to his methodology, was subjected to severe criticism by movants. Based on his study of these records, Mr. Bay constructed a number of cross-sections illustrating his picks of gas-oil contacts, or first producible oil. He defined "gas-oil contact" as a gravity segregation phenomenon resulting in a transition zone below which is oil and above which is gas. (Tr. 7108-7109). Mr. Bay did not attempt to pick a gas-oil contact within any formations underlying the Brown Dolomite "because of the distribution of porosity within each of these units being rather erratic and discontinuous, and, in

my opinion, being local reservoirs." (Tr. 7386). Within the Brown Dolomite, he did not find a single, uniform fieldwide gas-oil contact, but rather a number of contacts in different regions, ranging from a low of +150 to a high of +342. (Bay Ex. 52, 64). These variations were attributed to structural features which trapped oil at high levels in some places. Other than these places, which include the Mother Goose, Masterson, White Deer and Deep Lake Grabens, Carson County basin margin and Rockwall County School Land areas, he did not ascribe to the theory of high pools of oil in the Brown Dolomite advanced by Dr. Holmes.

Professor Wayne Ahr testified on reservoir fracturing for non-movants. Dr. Ahr studied cores from the J. M. Huber Co. No. 3 Crudgington and No. A-3 Otis Phillips wells and prepared exhibits detailing his findings. He asserted, in disagreement with Dr. Holmes, that fractures do not play an important role in fluid transmission through this reservoir. (Tr. 8191) He characterized the Brown Dolomite as an excellent reservoir with "ample porosity and permeability in the intercrystalline pore network . . . irrepective of fractures". (Tr. 8207)

Engineering

Clark Gillespie, petroleum engineer, performed a fieldwide study of the reservoir for non-movants and projectd remaining oil recovery at some 100 million barrels. (Tr. 8477 line 8). By his calculation, except in the Moore and Potter County areas, the drilling of new oil wells "has not *significantly* altered the projected ultimate recovery of oil from the field". (Tr. 8541 lines 8-17, emphasis supplied). He speculated that there might be some unusual reservoir characteristics along the northern flank of the Moore County platform area which contributed to higher oil averages in that region, but felt a need for further study before making a firm conclusion. (Tr. 8972 lines 7-16). In Mr. Gillespie's opinion, efficient gravitational

segregation over most of the field caused the accumulation of gas in the structurally high parts of the field and the accumulation of oil in the structurally low parts, with exceptions in a few anomalous areas such as the Deep Lake, White Deer, Mother Goose and Lefors Grabens. (Tr. 8473). This opinion was based on his examination of some 10,000 old cable tool drillers' logs. Gillespie exhibit 32, a histogram of first reported shows in these wells, shows that of 6324 reporting oil encounters, 95% occurred below +250 feet. (Tr. 8578). He prepared a number of cross-section exhibits (52-55b) showing his picks for gas-oil contact or transition zones, and concluded that as a general rule, "when producible oil and gas zone gas occur in the same wellbore, a gas-oil contact is present and can be identified." (Gillespie Ex. 2). Mr. Gillespie did not assert that there was a single unified contact across the entire field. (Tr. 8923-8924). He found some variation in the contact level, and on occasion could not pick a contact at all. (Tr. 8755 line 14).

When questioned on his definition of gas-oil contact, Mr. Gillespie offered the following:

> "The gas-oil contact is a point which may be defined with respect to initial fluid distribution or capillary pressure, with considerations as to the point of zero capillary pressure or the point below which the porous permeable rock is entirely filled with liquid. That is, perhaps, a rigorous reservoir engineering definition.
>
> I think it can also be defined, and I have defined it, I believe, in other matters, as the point above which commercial oil production cannot be obtained. And that would probably be a point at the upper portion of the so-called transition zone above the 100% liquid level.
>
> * * *
>
> The one that I have used with respect to my testimony in this proceeding today would be the latter.

I do not certainly disagree with the first one that I stated; that is, the point of 100% liquid saturation but I believe that in a practical oil field operation that certainly with regard to drilling completion, the latter would be the one that would be more commonly utilized."

(Tr. 8875-8876).

On cross-examination Mr. Gillespie's attention was directed to a number of instances of shows of oil above what he would pick as a gas-oil contact. (Cross-examination ex. 26-32). He was of the opinion that these shows did not indicate producible oil. (Tr. 9028).

Mr. Gillespie discussed a recent trend of increases in casinghead gas withdrawals which he considered excessive. (Ex. 63D-F). The examiners consider these exhibits very important and have reproduced them in appendix 3.

Examiners' Opinion on Reservoir Theory

The examiners are of the opinion that there was efficient gravity segregation of hydrocarbons in the majority of the Panhandle field, such that it is frequently possible to pick a gas-oil contact by one of several means. We believe that there is residual oil high in the dry gas cap, but that saturations are generally so low as to be immobile to flow and production in practical quantities. "Practical" as used here means that quantity which would attract a prudent operator to drill an oil well.

Gas-Oil Contact

The presence of a gas-oil contact or transition in this field has been noted or inferred for decades.

"The upper limit of this oil zone is about 200 feet above sea level whether the oil is found in granitic sands or dolomite."

(CIG Ex. 5; Baur, *Oil and Gas Gields of the Texas Panhandle*, 10 Bull of Am. Assoc. of Pet. Geologists 733, 744 (August, 1926))

"Oil is usually found where the positions of the porous formations lays from 110 feet above sea level to nearly sea level. There are, however, exceptional occurences."
(CIG Ex. 1, RRC Director of Production V. E. Cottingham, Docket 108, p. 355 [November 19, 1935])

"Gas is found in all of the producing formations where present on the higher parts of the regional structure, oil being present on the north flank and maintaining a general level between sea level and 200 feet above."

(Herrmann Cross-Examination Ex. 3; *History of Development of General Geology of the Panhandle Fields of Texas*, 12 Panhandle—Plains Historical Review, p. 7 [1939])

"According to Mr. Rogatz,[1] the oil is found between gas-oil and oil-water contacts and all of the oil, water and gas is considered as being one huge system."
(CIG Ex. 2; RRC Engineer James Hall, Docket 10-17,040, pp. 4-5 [January 12, 1950])

"Anywhere across this field . . . the position of the gas-oil contact holds esentially the same position with respect to sea level . . . regardless of whether the oil is in the Granite Wash or whether it is in the White Dolomite or the Brown Dolomite."

(G. L. Knight, Phillips Petroleum Company District Geologist, *Id.* at 16.)

The examiners have no doubt that operators who do not look for a gas-oil contact will not find one. Some movants

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[1] Movants recognized Henry Rogatz as "a noted authority on the field" and "the grand old man of geology of the Panhandle Field." (Tr. 3007, 9552)

testified that they were unable to locate a contact or transition zone, but cross-examination evidence indicated that they were often able to pick contacts when convenient or requested in prior years:

Max Banks: "There is no gas-oil contact". (Tr. 1026).

But Baker & Taylor's own well files identify high perforations as located in a "gas zone" and lower oil perfs as located in an "oil zone" (Lambert cross-examination exhibits 3,5,6, and 8).

Bill Sutton: "I don't think you could pick a gas-oil contract". (Tr. 2396).

But on a Commission H-1 form Mr. Sutton himself previously listed a gas-oil contact for this well. (Sutton cross-examination exhibit 2).

Billy Gillman: "Every core that I've ever seen laid out from the top of the Brown all the way down always shows a certain amount of oil in it." (Tr. 2590).

But Mr. Gillman's company has filed at least one H-1 form (on their Haynes Lease—03776) showing a gas-oil contact.

J. B. Herrmann: "I can't find any (gas-oil contact) in my wells". (Tr. 3080).

But in 1966 one of Mr. Herrmann's employees in filling out an application to inject fluid (H-1 equivalent) listed a gas-oil contact of +150 feet on their Hardin Lease (00821) well no. 4. (Herrmann cross-examination exhibit 2).

T. M. Hatfield: "We can't identify a gas-oil contact in this field." (Tr. 3395).

But none of Mr. Hatfield's wells (which are located primarily on the Burnett Ranch) are open to the upper formations. (Tr. 3416)

The full text of Max Banks' remarks provides some revealing insight into the motivation for this recent inability to locate a gas-oil contact.

"We never knew the gas-oil contact was even a factor in an oil well up here. We find out now, after FERC gave you a crutch to limp with, that it is a factor, so now we have to prove that there is no gas-oil contact." (Tr. 1026).

The examiners suggest that when both commercially producible oil and dry gas are present in a wellbore, it is almost always possible to locate a gas-oil contact or transition zone by one of the following methods:

1. Selective Interval Test

Many of movants' witnesses were in agreement that an operator *who desires to do so* can determine oil and gas intervals in an individual wellbore by isolating various depths with retrievable bridge plug and packer or other methods and testing the isolated interval for production.

Chester Lambert: "It's possible, yes." (Tr. 1120 line 25)

Frank Groce: "True." (Tr. 2322 line 21)

S. Gray Johnston: "That's correct." (Tr. 2939 line 23)

Carroll Beaman: "Quite elementary". (Tr. 3173 line 8)

Rex Howell: "Yes . . . most of them (intervals in his wells) were selective isolated by a packer and a bridge plug." (Tr. 3660-3661)

Michael Holmes: "In terms of identifying fluids within the reservoir . . . you can complete the well and test it individually." (Tr. 4115-4116)

S. Gray Johnston, Petroleum Engineer witness for the Moore County Royalty Owners Association, testified that most of the operators he worked with selectively tested their zones as a matter of course. (Tr. 2939).

2. Wireline Logs

Most of the witnesses in this proceeding were not professionally qualified to interpret wireline logs. Those who were agreed that this type of data could assist in picking a gas-oil contact.

> Frank Groce: Log water saturation calculations are "90 percent accurate . . . in depicting whether you have oil or gas production from where you're perforated." (Tr. 2218) *and* Neutron/density crossover "indicates that there is gas there." (Tr. 2324)
>
> [Two curves are compared for crossover. The density log curve is produced by a shallow-reading tool and the compensated neutron log curve is generated by a tool which "sees" back about a foot into the formation.]
>
> Bill Sutton: "Yes." (Q—"on the porosity log if you had a neutron density cross-over, that that could be productive of a gas only zone?") (Tr. 2460)
>
> Michael Holmes: "I conclude that in general the fluids in the matrix can be determined from logs." (Tr. 4021) "The logs emphatically tell you where the oil and gas and the water are located." (Tr. 5046)
>
> Clark Gillespie: "Under the proper circumstances with the proper suite of logs being available . . . one may be able to observe the ending of gas effects and thereby gain a pretty fair indication of whether or not a gas-oil contact has been penetrated." (Tr. 9104)
>
> "This is a tool that may be used, although I would also have to say that although logs are a tool that may be used, regrettably many operators . . . most operators do not run a suite of logs that even comes close to permitting the identification of a gas-oil contact from well logs if one has been penetrated." (Tr. 9106)

3. Cable Tool Log Records

These records of fluids and formations encountered in over 10,000 early wells exist in several geological libraries and depositories around the state. During the Depression one of President Roosevelt's W.P.A. projects included sorting and cataloging these records, which are on file among other places at the University of Texas Bureau of Economic Geology. The fluid levels reported by observers on these wellbores are generally consistent; 95% (of 6324 reporting oil encounters) showing first oil at or below +250 feet. (Gillespie exhibit 32). The accuracy and reliability of these records was attacked by some witnesses for movants; for example, petroleum engineer Miles Reynolds commented: "My opinion is that the cable tool drilling record information is not a reliable tool in trying to determine where all potential zones of productivity are." (Tr. 5853). This was a rather carefully qualified condemnation. Those witnesses who were familiar with the cable tool drilling and logging process generally agreed that the records were a valuable tool for determining fluid locations in the reservoir:

> Bill Murray: (Cable tool driller's logs are) "as reliable as anything that existed then, and I'm not sure there is anything that is better now" (for locating first appearance of oil).
> (Tr. 197)
>
> Clark Gillespie: "I certainly do agree with it (the statement that driller's logs are comparable to a continuous open hole drillstem test) . . . Cable tool drilling method has as one of its obvious principles that one uses a rock bit to pound up the rock into small chips that can be removed from the wellbore with a bailer . . . the driller, his tool dresser, or geologist, if he was onsite, could observe almost on a foot by foot basis the nature of the rocks and what, if anything, was coming into the wellbore . . . I would say that in many cases the—a cable tool

driller's log would be a better and more reliable indication of what the formation contained at the time of drilling and would be perhaps less subject to interpretation of modern well logs would be."
(Tr. 8549-8550)

Michael Holmes: "If we are drilling wells, as was done in the early days, with cable tools, we have essentially a continuous drillstem test on the well, from which if we're careful in our records, and if the data allow us to do this, we can record flows of gas, shows of oil, mists of oil and so on."
(Tr. 4115)

Chester Lambert: "I don't question what's on the logs."
(Tr. 1129)

Tom Bay: "When we pulverize this rock with the cable tool driller, with the bit hitting on that rock, that, in my opinion, breaks it up more than any fracturing that one might do in the subsurface in order to stimulate the flow. So, if there is any oil in that matrix, we certainly should see it when we do pound that rock and pick it up in that bailer."
(Tr. 7920-7921)

The examiners are of the opinion that cable tool drilling records are a generally reliable indicator of fluid levels and helpful in picking a gas-oil contact or transition zone.

4. Coring and Sample Cuttings

A number of witnesses for movants conceded that examination of returns from wellbores was useful in picking fluid levels. Comments in this regard:

J. B. Watkins: "The process that I normally use in drilling and completing wells from a geological and completion standpoint is to examine the cuttings, and where you have live shows of oil, use

that as a basis for the top part of your producing formation if you're drilling an oil well."
(Tr. 3823)

Bill Sutton: "I would core a well and use the core information for completion."
(Tr. 2445)

Q: "You've indicated that the core analysis indicates what intervals are likely to be productive of gas and what intervals are likely to be productive of oil."

A: "Yes."
(Tr. 2457)

Michael Holmes: "Another source of information is mud logging, of monitoring of the mud stream or the fluid stream from which you are drilling the well, as to what hydrocarbons or what materials are being brought to the surface."
(Tr. 4115)

"Another source of data is core information. Cut a core and you can measure fluids in that core and make interpretations, make estimates, at least as to what—at least you know what fluids are there, and then perhaps estimate what might be there before the flushing process of the coring."
(Tr. 4116)

"I'm sure you're aware that oil fluoresces; in other words, if you bombard it with ultraviolet light, it reflects back in the visible spectrum . . . and it represents the presence of oil."
(Tr. 4130) [See also Tr. 4135]

Chester Lambert: Q: "Do you recall the question that was asked you about distinguishing between oil show versus gas show by Mr. Cochran?

A: Yes, I do.

Q: Let me ask you very simply: does gas reflect a fluorescence or is it just oil that reflects a fluorescence?

A: Oil is what reflects a fluorescence."
(Tr. 1182)

The examiners are of the opinion that analysis of formation samples is a useful tool for locating a gas-oil contact.

5. What the Neighbor Found

The examiners are in agreement with the assertion of Clark Gillespie that one task prudent before drilling new wells is the prior analysis of "production performance of the nearby leases." (Tr. 9091). Some witnesses for movants conceded the value of this analysis in predicting the location of oil zones:

> Frank Croce: Q: "And that type of study of surrounding producing wells has been to assist you in knowing where to perforate for oil and where to perforate for gas; is that right?
>
> A: That is a tool used in that procedure, Yes." (Tr. 2322)
>
> Billy Gillman: "You rely on the knowledge of similar wells in close proximity of the well you're working on."
> (Tr. 2622)

Perforation and completion information is readily available for all wells in the field, either by analysis of Railroad Commission files (W-2 data) or purchasing the relevant statistics from one of the commercial reporting services.

The examiners concur with the opinions of many experts over the decades that where commercially producible oil and dry gas are both present, the two generally meet at a gas-oil contact or transition zone which can be located *if desired.* We agree with Bill Murray, who testified, "I have clearly stated from a conservation engineer if it is possible, when it is possible to determine a gas-oil contact, it is desirable for conservation reasons to perforate below the gas-oil contact." (Tr. 131). Mr. Murray was of the opinion that such determination is not possible in the Panhandle fields, and we respectfully dis-

agree with his conclusion. Operators have managed to pick a gas-oil contact on the H-1 forms for many years, generally without problems, and did not report difficulties to the Commission until after the FERC hearing. Two generations of operators have come and gone without leaving a substantial trace of this difficulty in transcripts of prior proceedings concerning the field, and we can only conclude that they had no such problem. These difficulties in picking a gas-oil contact are a notably new development.

No party asserts that there is a *single, uniform* gas-oil contact across the field. The cross-sections prepared by Mr. Bay show that there are regional contacts which vary with structure as should be expected in a field of 1.7 million acres. Some of these contacts may be in reality transition zones of up to 50 feet in thickness, but the evidence shows they can generally be located where present.

Fractures

The examiners made a personal inspection of core samples from the study wells and conclude that the Brown Dolomite is not "widely fractured" with fractures still open as asserted by Dr. Holmes. (Tr. 9581). We agree with Dr. Ahr that "the bulk of those things are filled with anhydrite—and they are very small." (Tr. 8115). Scanning Electron Microscope and thin section photographs submitted by Dr. Ahr show that there is no need to postulate a complicated fracture matrix system to explain Brown Dolomite oil production. We note that each side provided thorough analysis on only two cores and feel that this is not much evidence on which to judge a field of 1.7 million acres, but based on what we have seen we do not find pervasive open fracturing in the Brown Dolomite. In a 1961 paper for the Panhandle Geological society, Henry Rogatz noted fracturing in all formations but concluded that due to extensive an-

hydrite impregnation within the Brown Dolomite "there is trapped a goodly part of the oil in the individual pores . . . [so that even with a waterflood] . . . large quantities of oil will be irretrievably trapped within the formation." (Bay Cross-examination Ex. 25, page 35). We are in agreement with Mr. Rogatz.

Catchment Basins

Dr. Holmes postulated traps of perched oil being held in the Brown Dolomite by anhydrite seals or carbonate mud flat deposits. The examiners have problems with Dr. Holmes' logic, which was somewhat convoluted in explanation of the genesis of these deposits. He conceded that the formations were originally full to the cap with water, which was pushed down by encroaching oil of a lighter density, and then had to explain why his traps were not full of water rather than oil. He accomplished this by assuming that the permeability barriers were in fact semi-permeable and acted as a barrier to downward flow of oil but *not* water. (Tr. 4663, 4677, 4697-4698, 4711) This seemed too convenient to the examiners and they requested data on the relative molecular sizes of water and oil molecules. The following was provided:

Water	.3	nm
Methane	.38	nm
Benzene	.47	nm
N-Alkanes	.48	nm
Cyclohexanes	.54	nm

(Tr. 4713)

Dr. Holmes' theory requires that his semi-permeable membranes permit the passage of a molecule .3 nm in size, but not .4 nm. No evidence was submitted to support such a precise limit, and the examiners are of the opinion that this remains an unproven theory. We do disagree with Dr. Ahr's assertion that the Brown Dolomite is porous and permeable from top to bottom. Analysis of

Bay Exhibits 72-78 show the following instances of intervals at least 8 feet thick with 0% to 1% porosity. (Disregarding shale breaks and the top 50 feet of the formation.)

- — Huber No. 3 Crudgington From 2365 to 1372 feet
- — NGPL No. 1-1 Bennett from 2628 to 2638 feet
- — HNG No. 1 Sneed "A-2" from 2410 to 2420 feet
- — Cities Service No. 4 Burnett B-3 from 2653 to 2661 feet
- — Top O'Texas Prod. No. 2 Hayden from 2684 to 2692 feet.

It must be conceded that there are a few uncontrovertible instances of producible oil high in the Brown Dolomite above an expected gas-oil contact.

1. The J. M. Huber No. 66 State of Texas -A- well, located about 1 mile south of Mr. Bay's line M-M', tested 1.5 BOPD and gas TSTM from perforations at +367 to +461. Mr. Bay's pick for top of transition zone in this area is +244. (Tr. 7766-7767).

2. The Phillips Petroleum Co. No. 10 Osborne well, located about 3 miles south of Mr. Bay's line A-A', tested 24 BOPD and 5600 mcfg/d (statutory gas well) from perforations at +452 to +562. Mr. Bay picks this Brown Dolomite area as gas only. (Tr. 7772, Bay Cross-examination Exhibit 3). The Osborne No. 2 well nearby is perforated from +282 to +402 and after 1975 workover and reclass to oil tested 4.1 BOPD and 264 mcfg/d. (Bay Cross-examination Exhibit 3).

3. The Sesco Operating No. 5 Laycock is perforated from about +300 to +500 in the Brown Dolomite in Wheeler County. IP was 2 BOPD and 17 mcfg/d. (Holmes Exhibit 55 A-1).

4. The Rockwall Petroleum No. 1078 Roberts is perforated from about +425 to about +525 in the Brown Dolomite in Gray County. IP was 11 BOPD and 53 mcfg/d. (Holmes Exhibit 55 A-1).

These and a few other occurrences of "ghost oil"; high, commercially producible oil with no known explanation, are rare. The majority of other instances submitted by movants of high oil in the Brown Dolomite have structural explanations as analyzed in Bay Exhibit 80 and summarized in Appendix 1.

RESERVES

High Matrix Oil

The examiners have not seen substantial evidence to support the position taken by movants that high residual oil is producible. The most dramatic evidence against producibility was the frustration encountered by Dr. Holmes in his effort to get oil to flow from a high level in the Celeron No. 16-12P Bivins well. He was present when the well was cored, and saw live oil high in Brown Dolomite.

> "I left the cores on the pipe rack, and if you [came] back every five minutes or so, you would see more oil coming out of the fracture system, and even a week or so later, . . . we cracked them open and there it was. You could smell it. There's live oil, very high in the structure."
>
> J. E. Watkins: "The process that I normally
> (Tr. 4125-4126)

In answer to a question by examiner Osborn about producibility of this oil, he responded:

> "I think you would have to test the well for probably a matter of days, maybe even a matter of weeks, before you would see the response of the oil." (Tr. 4162)

Based on what he saw, Dr. Holmes recommended various perforations to Celeron in an attempt to produce this high

oil. Celeron made the perforations but was unable to produce *any* of this high oil in *34 days* of testing. Holmes' conclusion:

> "The poor reservoir doesn't have any energy down there."
> (Tr. 4150)

Dr. MacDonald, chief engineering witness for the new operators, agreed with Geologist Holmes' interpretation of the fracture-matrix theory of the reservoir and performed studies to make a calculation of the amount of oil in place in the traditional dry gas area of the reservoir. Based on these studies he concluded it is "possible to recover in the neighborhood of four to five hundred million barrels" from this area. (Tr. 6653-6654). Two studies formed the basis for this conclusion; a compositional material balance analysis and a volumetric analysis. The former generated a figure of 2.5 billion barrels of oil in "intimate contact" with the dry gas, being the amount calculated as necessary to cause the rise in specific gas gravity seen in the field. (Tr. 6232). The latter generated a figure of 85.5 billion barrels of oil in place of whicch he conceded a "very small fraction" would be recovered (MacDonald Exhibit 39, Tr. 6359).

The volumetric calculations performed by Dr. MacDonald are subject to substantial variation in results with minor changes in input. His formula will not work for R sub S values higher than about 177 (solution gas measured as a ratio of standard cubic feet per stock tank barrel on discovery). (MacDonald Cross-Examination Exhibit 22, Tr. 6405, 6409). He testified that he had heard that R sub S in the field ranged from 140 to 230, but that he had not "really looked at that top range" (Tr. 6412, 6415 lines 9-19). By way of example of the input sensitivity problem, if Dr. Holmes' calculation of hydrocarbon volume of 35 million acre feet was high, and actual volume was 30 million acre feet, the resulting value drops from 85.5 billion barrels to 9.4 billion

barrels. (Tr. 6418). Similarly, if the calculation of gas in place in the gas area was revised downward from 40.3 trillion cubic feet to 37 trillion cubic feet, the resulting value for oil in place increases to 121 billion barrels. (Tr. 6438). All of these figures far exceed MacDonald's calculation of cumulative oil production of 1.24 billion barrels over the last 70 years. (Tr. 6651-6652).

Volumetric and Compositional Material Balance equations are subject to another limitation which was acknowledged by Dr. MacDonald; neither indicates whether oil is spread uniformly through the rock at low saturations or concentrated in fractures or other accumulations. These equations do not provide information about the location of oil within a formation. (Tr. 6422, 6493).

The fundamental premise behind Dr. MacDonald's work is his reliance on Dr. Holmes' fracture-matrix theory of the reservoir. Dr. MacDonald's production forecast model assumes casinghead gas production will "put a drawdown on the matrix (and) more oil into fracture(s) for subsequent production". (Tr. 6339-6340). But he conceded that fractures had been reported without regard to whether they might be filled with anhydrite or some other barrier to flow. (Tr. 6533 line 9). A lack of discrimination in this regard detrimentally affects the reliability of the conclusion as to producibility of the "intimate oil" calculated by the witness.

The examiners are of the opinion that residual oil saturations in the gas cap are in most instances locked up too tight to flow to a primary recovery well. Dr. Richard Strickland and Dr. James Johnson performed tests to simulate reservoir conditions and submitted conclusive evidence that residual saturations were generally immobile to flow. Dr. Strickland agreed that Dr. Holmes' capillary pressure was a valid explanation for high residual oil saturations, but asserted that for the most part this oil could not be produced to the surface. (Tr. 8422).

A number of other experts referred to this or other high immobile oil as "dead oil". (See Frank Groce at Tr. 2367, Tom Bay at Tr. 7789 and Miles Reynolds at Tr. 9368).

The examiners are of the opinion that they have not been presented with a reliable estimate of the amount of *recoverable* oil existing in the traditional gas area of the field. The evidence supports a conclusion that some amount does exist, and the presence of some undiscovered amount is therefore not unreasonable, but the examiners have not seen convincing proof that the 400 to 500 million barrels of recoverable oil postulated by Dr. MacDonald can be produced. He asserts this oil can be produced "provided you place a pressure differential across this system" but later concedes that "the fracture system . . . does not really contact but a very small proportion of this total oil in place." (Tr. 6286, 6359). Dr. Ahr's evidence that many of these fractures are filled with anhydrite presages some difficulty in producing the oil which is present in the dry gas area of the reservoir.

Low Perf Gas Wells

If some new operators in the field are guilty of overaggressive completion practices, the same is true of some old operators. Just as an oil well operator is required to stay out of a dry gas zone, a gas well operator should stay out of any oil zone below the gas he is producing, refraining from ripping his casing top to bottom in a horizon where any free gas removal will diminish drive energy required for oil recovery. Movants did not give much attention to this problem, but examiner questioning during the hearing and analysis of the exhibits indicates that some operators when completing gas wells may not take particular care to stay out of deeper oil bearing horizons or horizons productive of oil nearby. The following are presented as examples of this problem:

1. C.I.G. No. A-3 Crawford gas well

A 1973 well perforated from +326 to+1197 across the fractured granite basement, Granite Wash, Moore County Lime and Brown Dolomite. This well with IP of 7758 mcf/d, is located some 9000 feet south of the Hufo No. 3 Johnston oil well, which was completed in 1980 for IP of 8 BOFD and 180 mcf/d at a GOR of 22,500:1; perforations +352 to +542 in the fractured granite *only*. (Bay Exhibit 59, assuming Hufo correctly reported perforations).

Examiner Cloud: "What about the gas in the basement there? Don't you think it is helping to drive the oil to the Hufo No. 3 Johnston oil well? Don't you think that gas needs to be conserved against the oil production in the Hufo No. 3 oil well which is down dip?

Tom Bay: Mr. Examiner, you are asking me questions beyond the scope of my study on this." (Tr. 7506)

2. C.I.G. Nos. A-4 and A-17 Kilgore

A-4 is a 1955 well with IP of 885 mcfd, perforations from +124 to +684. A-17 is a 1969 well with IP of 5600 mcfd, perforations from +169 to +818. Both wells are completed deep into the Arkosic Dolomite. (Bay Exhibit 64)

Adjacent is an oil well, the Hufo Production No. B-5 Johnson, perforated from +780 to +233, 1983 IP of 7.1 BOPD at a GOR of 63,904:1 (this well is probably perforated too high, see Tr. 7538). Two and 1/2 miles west is the Texas Gas Producing Company Brown Lease, with several abandoned oil wells. The closest of these, the No. 1 Brown, tested 71 BOPD at a GOR of 2436:1 on a 1961 test from perforations at +304 to +312. This lease(s) was abandoned in 1968 with cumulative production of

61,400 barrels of oil. (Letter of November 9, 1987, counselor Elizabeth Miller to Examiner Osborn). One must question whether excessive production of deep gas by C.I.G. caused the premature abandonment of these oil wells by depleting their drive energy.

Examiner Osborn: "Let's look at the CIG A-17 Kilgore. Do you feel that the perforations in that gas well below the Arkosic Dolomite—Moore County Lime contact should be squeezed off?

Tom Bay: "That I don't know sir, because we have not made a gas-oil contact study in the Arkosic Limestone and Granite Wash." (Tr. 7538).

3. C.I.G. No. A-2 Read gas well

   A 1937 well perforated from +600 to +1202 across the Granite Wash, Arkosic Dolomite, Moore County Lime and Brown Dolomite. 1937 IP was 56,700 mcfd, and following 1955 workover and deepening increased to 68,000 mcfd. (Bay Exhibit 66)

4. Kerr-McGee No. 1 Wilbar gas well

   A 1935 well perforated from —6 to +703, this well is located in Gillespie study area 10 where he picks a gas-oil contact at +160. Clark Gillespie: "I would think . . . the lower part of the well should be plugged off." (Tr. 8744)

5. Diamond Shamrock No. 2 Schlee gas well

   A 1985 well perforated at various intervals from +173 to +729 in the Arkosic Dolomite, Moore County Lime and Brown Dolomite. 1985 IP was 3420 mcf/d. (Bay Exhibit 58). Clark Gillespie testified that pressure depletion of the Arkosic by the Schlee well "could, to some extent" affect the gas-drive movement of oil to nearby oil wells. (Tr. 9223)

6. Conoco No. 2 E. L. Smith gas well

   Total depth of 3230 feet, with top of oil zone indicated by company records at 3172. Maston Powers,

Conoco Engineer, conceded "they really should have plugged it off." (Tr. 6977 line 14).

Examiner Osborn: Mr. Gillespie, you're showing six or seven wells, I believe, gas wells completed down into the Granite Wash?

Clark Gillespie: Yes.

Examiner Osborn: Does the gas produced from those wells dissipate drive energy used to produce Granite Wash oil?

Clark Gillespie: I think, as the studies of Dr. Strickland indicated, whether a gas well or an oil well is perforated above the gas-oil contact, the withdrawal of gas either by an oil well or a gas well perforated above the gas-oil contact immediately above an oil zone may have some detrimental effect on oil recovery. (Tr. 8624).

Lest there be any doubt that some gas wells are perforated down into oil bearing zones, attention is directed to Stumpf exhibits 14-18 concerning gas wells reclassified to oil with no downhole workover. These wells, the El Paso Natural Gas Wattenbarger -A- Nos. 3 and 4 and Bell No. 5-D, and the Texaco B. H. Love No. NCT-1-3 well, all made very little oil on new IP after conversion, with an average of only 1.3 BOPD. The question remains, what production would they have made if produced for oil 25 years ago when they were new wells and the reservoir pressure was substantially higher? We have no way of knowing.

Further attention is directed to Reynolds exhibits 6, 7, 20 and 21 illustrating other conversions from gas to oil. The Terra Energies J. R. Nicholson No. 1, drilled in 1961, was equipped to pump oil in 1973 and produced at a test rate of 9 BOPD with a GOR of 27,777:1. (Reynolds exhibit 6). This well is perforated from about +375 to +425 (from log; note discrepancy with schematic) and

is located in one of the Appendix 1(4) areas, Carson County Basin Margin (East), where a contact at +450 is assumed correct. The Crown Bobbitt no. 5 well, drilled in 1948 three sections to the east, was converted to oil in 1970 after fracture stimulation resulted in production of 31 BOPD at a GOR of 10,000:1. (Reynolds exhibit 7, see also Stumpf exhibit 18). This well is perforated from about +325 to +380, a level presumed acceptable since it is within the same special area as the Terra no. 1 Nicholson.

The Phillips Petroleum Osborne No. 2 was completed for gas in 1949, and recompleted for oil in 1967 from perforations at +282 to +402. (Reynolds exhibit 20, Bay cross-examination exhibit 3). A nine year history submitted as Reynolds exhibit 21 shows that this is a high GOR well, ranging up to 72,593:1 on 1978 test, but most recently it was making a 4 BOPD at a GOR of 14,250:1. The well is located in an appendix 1 (4) special area, the Deep Lake Graben, where a contact is presumed at +350.

Reynolds exhibit 20 illustrates four other gas completions (open hole) which went deep enough to hit oil, and 15 to 20 years later were reclassified from gas to oil:

Roy Production No. 4 Bills
Phillips Petroleum No. 1 Bralley -A-
Diamond Shamrock No. 10 Ryan
Diamond Shamrock No. 1 Myers

THE COMMISSION'S MANDATE

Statutory Requirements

The Railroad Commission has among its many jurisdictions the duty to regulate and prorate production of oil and gas in order to prevent waste, promote conservation and protect correlative rights (Tex. Nat. Res. Code §§ 85.201, 85.202(b), and 86.081(a)).

Chapters 85 and 86 of the Texas Natural Resources Code contain numerous statutory definitions of waste, of which the following are relevant in this docket:

1. § 85.046(a)(1)

   (1) operation of any oil well or wells with an inefficient gas-oil ratio . . . (Commission may prescribe permitted ratio).

   (3) underground waste or loss, however caused . . .

   (6) operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas in any pool

   (7) loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool. . .

2. § 86.012(a)(11) the production of natural gas from a well producing oil from a stratum other than that in which the oil is found unless the gas is produced in a separate string of casing from that in which the oil is produced.

The duty to protect correlative rights is addressed in the following relevant provisions:

1. § 85.202(a)(4)
2. § 86.042(5)

(The Commission shall) require wells to be drilled and operated in a manner that will prevent injury to adjoining property.

CASE LAW INTERPRETATIONS

The meaning of these statutory definitions and requirements and the Commission's obligations arising from them have been addressed by the Texas courts. Following are discussions and definitions from some of these cases:

1. *Gulf Land Co. v. Atalntic Refining Co.*, 131 S.W.2d 73, 80, 85 (Tex. 1939)

   Appeal of a Rule 37 Order

   > "The term 'waste', as used in oil and gas Rule 37, undoubtedly means the ultimate loss of oil. If a substantial amount of oil will be saved by the drilling of a well that otherwise would ultimately be lost, the permit to drill such well may be justified under one of the exceptions provided in Rule 37 to prevent waste.
   >
   > The Commission is not compelled to absolutely confine itself to the lone question as to whether such well will save oil that otherwise would be lost, but may also take into consideration waste above the ground, and the orderly and scientific development of the field."

2. *Hawkins et. al. v. Texas Co.*, 209 S.W.2d 338, 342, 344 (Tex. 1948) A benchmark Rule 37 case rejecting the theory of "more wells, more oil", this case expands on the use of the qualifier "substantial" in the *Gulf Land* case.

   > "There is no proof in the record that a *substan-tial* amount of oil would be saved by drilling the additional well. The only evidence suggesting the drilling of that well would prevent waste is the testimony of the witness Hudnall . . . he testified that the recovery of oil from the Hawkins tract would be increased by the drilling of an additional well. Thereupon, to the question whether the increased recovery would be a substantial or

only a trivial amount, he answered that it would be substantial in percentage, but due to the fact that the sand was thin the total amount would not not be very great. There is no evidence in the instant case that a *substantial* amount of oil would be saved by the drilling of a tenth well. The testimony is merely that the recovery of oil from the tract would be increased, or that a small quantity not otherwise produced or a greater percentage of oil would be recovered." (emphasis original)

3. *Phillips Petroleum Company et. al. v. American Trading and Production Corporation et. al.*, 361 S.W.2d 942, 945-946 (Tex. Civ. App.—El Paso 1962, writ ref'd n.r.e.)

A suit concerning ownership of proceeds from sale of illegally produced oil. The Court of Appeals addressed the role of correlative rights in Commission decisions.

"The function of the Railroad Commission with respect to the exercise of its regulatory powers in the oil and gas industry is not confined solely to the prevention of waste and the conservation of a natural resource. The Commission also has the duty, in cases where it has been determined (as it has here) that a common reservoir exists in which numerous parties share certain rights and interests, to promulgate field rules and orders applicable to such common reservoir for the protection of the correlative rights of all who are entitled to take from the common reservoir or share in the proceeds from such production.

Conservation statutes and orders of the Railroad Commission . . . are designed to afford each owner a reasonable opportunity to produce his proportionate part of the oil and gas from the entire pool and to prevent operating practices injurious to the common reservoir.

The consensus of authority appears to hold that the right of an owner to recover oil and gas from beneath his own land is qualified and is limited to "legitimate operations". Each owner whose land overlies a common reservoir has a like interest, and each must exercise his right with some regard to the rights of others, and must submit to such limitations as are necessary to enable each to get his own."

4. *Railroad Commission v. Manziel*, 361 S.W.2d 560, 572 (Tex. 1962).

Dispute concerning a waterflood injection program.

"The Commission has two primary duties in the administration and control of our oil and gas industry. It must look to each field as a whole to determine what is necessary to prevent waste while at the same time countering this consideration with a view toward allowing each operator to recover his fair share of the oil in place beneath his land. In carrying out these duties, there has devolved upon the Commission the power to promulgate rules, orders and regulations that control the industry, and such are issued pursuant to the police power of the state, and that power may invade the right of the owner of the land to the oil in place under his land as long is it is based on some justifying occasion, and it is not exercised in an unreasonable or arbitrary manner.

It follows from the nature of oil and gas that the use by one of his power to seek to convert a part of the common reservoir to actual possession may result in an undue portion being attributed to one of the possessors of the right to the detriment of the other. Hence, it is within the Commission's power to protect the vested rights of

all the collective owners, by securing a just distribution, and to reach the like end by preventing waste."

Celeron et. al. discuss this case in their closing statement at page 38, and take the position that it has no relevance since it is addressed to "drainage *across lease lines*" (*id.* at 572, their emphasis supplied). They reference the Natural Resource Code § 85.202(a)(4) duty to prevent "injury to *adjoining property*" (their emphasis supplied) and assert this protection does not extend to severed gas rights, which are instead "akin to the rights of an undivided interest owner in a tract". (Celeron Closing, p. 38). The Legal Examiner respectfully submits that the more appropriate analogy would be to horizontal severance of mineral rights into two separate estates, each meriting protection of correlative rights. "Horizontal divisions of the oil, gas and other minerals under a tract of land creates estates of equal dignity. There is no lesser and greater estate involved." *Gibson Drilling Co. v. B & N Petroleum, Inc.*, 703 S.W.2d 822, 826 (Tex. App.—Tyler, 1986, no writ). While not exactly the situation at hand, this seems the better analogy given the concept of an upper dry gas zone above the oil and water zones which was generally accepted in the 1920s and early 1930s when the interests were severed.

Celeron et. al. take the position that if there were correlative rights deserving protection, they no longer exist because "all of the gas which was in the gas phase when the field was discovered has [already] been produced by the gas wells." (Celeron Reply p. 38, citing "Dr. MacDonald's unrebutted testimony" at Tr. 6360). *However*, Dr. MacDonald later conceded that *the same was true* for casinghead gas production from oil wells, calculating for this a cumulative total of some 6.4 trillion cubic feet, being about twice the amount of solution gas which he calculated was originally present in the traditional oil rim. (Tr. 6423 line 10, 6424-6425).

Given that correlative rights in the field are deserving of protection, how shall this privilege be reconciled here where it conflicts with the Commission's mandate to prevent waste? The Commission has faced this dilemma in the past, and it is clear from the case law that prevention of waste is the dominant mandate.

> "Between protecting correlative rights and protecting the public interest of preserving our state's natural resources, the prevention of waste has been held to be the dominant purpose. The Commission, by controlling the oil stored in a common reservoir, is enabled to carry out the dominant purpose of preventing waste.

Texaco, Inc. v. Railroad Commission, 583 S.W.2d 307, 310 (Tex. 1979).

To say that a concern is dominant does not mean that it is exclusive. In the case of *Railroad Commission of Texas v. Fain*, 161 S.W.2d 498, (Tex. Civ. App.—Austin 1942, writ ref'd w.o.m.), Awoeb Oil Company challenged a Commission fieldwide proration order for the Minnie Bock oil field in Nueces County, asserting that the order caused waste in their company's three wells. The court considered a conflict in Commission mandates and stated:

> "Even if it be admitted that all of (Awoeb's) contentions as to waste applicable to their particular wells be true, the Commission was confronted with the problem as to how conservation as to the entire field would best be subserved; and must decide that question with reference to the field as a whole. . . When they (statutory definitions of waste) conflict, or present a dilemma, as they appear to have done here, it is for the Commission to determine what on the whole will best conserve the natural resources. And if that determination finds support in substantial evidence, though the evidence be conflicting, the order should stand." (*Id.* at 500).

To Awoeb's assertion of confiscation, the court replied:

> Nor is the fact that the Commission's order will result in economic loss to appellees controlling. Any order of the Commission limiting density of drilling, daily allowable per well, or controlling storage, transportation and marketing necessarily affects property values and profits from production of oil. But this is necessarily incident to the police power of the state to regulate any business affected with a public interest, so long as it treats all alike. (*Id.* at 500).

Celeron et. al. assert that "(b)ased on the facts of this case (Docket No. 10-87,017), the Railroad Commission must confine its attention to the issue of waste only". (Brief of Celeron et. al. on Waste vs. Correlative Rights, p. 9). The examiners are of the opinion that prevention of waste, though our dominant concern, is not an exclusive one and must be balanced to at least some degree against other considerations of injury to the field in terms of damaging ultimate recovery prospects and harming correlative rights. "[In] carrying out this constitutional purpose [to conserve natural resources], the Commission must, as far as possible, act in consonance with the vested property rights of the individual." *Marrs v. Railroad Commission*, 177 S.W.2d 941, 948 (Tex. 1944).

BALANCING THE MANDATE

How Much Casinghead Gas is Necessary?

Although it is asserted by some parties that a generous daily casinghead gas limit is needed to *produce* tight oil trapped in the matrix of the reservoir, the more frequent reality seems to be that high casinghead gas production is necessary to *finance the operation* of oil wells which often might not even be drilled without a chance for the casinghead gas revenue. The operations of Baker & Taylor Drilling Company (Max Banks) are typical in this regard. In 1984 Mr. Banks purchased all

mineral rights (oil and gas) in two sections of land in northeastern Moore County and proceeded to drill six oil wells on one section and eight oil wells on the other, each formerly having one (abandoned) gas well only. Commission records show production in 1984 of 4513 barrels of oil and 53,111 mcf of casinghead gas, and in 1985 of 4600 barrels of oil and 380,678 mcf of casinghead gas. At the end of 1985, local gatherers notified Mr. Banks that they would for various reasons decline to take any more of his casinghead gas, and as a result he is now shut in. He testified that under a Section 103 new gas price of about $3.00 per mcf "it was a good economic play" as long as they were able to sell their casinghead gas without any problems, but that without this revenue the wells were not profitable and circumstances do not merit completion of any more oil wells. (Tr. 968, 976). Based on the production figures reported to the Commission (1985 oil production ledger data), the least GOR for the year of 1985 was 82,756:1, coming close to the cutoff for statutory gas wells. Mr. Banks testified that under these conditions he would "just drill and drill and drill" for oil. (Tr. 1028). But, as his vice-president for drilling contracts (Chester Lambert) subsequently testified, "You would have to have some casinghead gas to make these wells economical." (Tr. 1196 lines 19-20).

Hermann Oil & Gas Company, J. B. Hermann, operator, owns oil and gas rights on his Killough Lease in Hutchinson County. This lease is located within the traditional oil rim area and Mr. Hermann proceeded to drill 10 oil wells with good results, but found that Phillips Petroleum refused to take his casinghead gas. He asserted that he went to them before completing his no. 7 well and asked where he might perforate to their satisfaction, but after so completing they refused to take his gas anyway. Phillips did not put on any evidence to counter his allegation, but in fairness it must be noted

that Mr. Herrmann did not accurately report high perforations on his W-2 forms at all times. Cross-examination Exhibit 1 shows that such perfs at +290 to +320 in his Killough No. 2 well were not reported. When asked why he perforated this high and did not report it he conceded that the resulting gas was "probably not" necessary to lift oil from lower zones, but stated that "you need to have all of the intervals producing that will produce for an economical well." (Tr. 3107 line 2, Tr. 3105 lines 17-19).

Enron Oil and Gas Company has about 40,000 acres of land under lease between Dumas and Fritch in Moore and Potter Counties. Some 25 wells have been drilled under this lease, which conveyed oil rights only. Twelve of the wells failed to test a GOR below 100,000:1 and all are currently shut in due to lack of pipeline connection for their casinghead gas. Mr. Rex Howell, executive vice-president, testified that casinghead gas was the "principal value" in drilling decisions, not oil. (Tr. 3638 line 3). Some of the oil shows reported by Enron are for quite small amounts, such as 4 gallons and 1.2 gallons. (Tr. 3676 line 6, Tr. 3685 line 10).

GMC Company operates 16 oil wells in the traditional oil area of the field, with production from each averaging 3 BOPD. Frank Groce, geologist and part owner, testified that these and most wells in the oil column are only "marginally economically productive". (Tr. 2302 lines 2-3).

J. B. Watkins operates the Bell leases some eight miles southwest of Pampa with eight oil wells perforated in the Brown Dolomite. He agreed that casinghead gas revenue was critical to the economic feasibility of oil production.

> "I think that the drilling by the independents and the majors both will be substantially reduced if the amount of casinghead gas that you are allowed to sell is materially reduced . . . And if the GORs are

materially reduced, that's going to make the wells uneconomical to drill."
(Tr. 3904).

From a total of 9 wells on the leasts, Mr. Watkins has cumulative oil production of 17,000 barrels, with individual GORs ranging from 10,000:1 to 150,000:1. (Tr. 3843).

The Burnett Dixon Creek (6666) Ranch sponsored a study of production on their spread of some 110,000 acres in Carson and Hutchinson Counties, which is for the most part outside of the traditional oil area. Commencing around 1975 extensive exploration for oil, stimulated by rising crude prices, resulted in the completion of numerous wells. During the following ten years the producing oil well count rose from 468 to 832, with an increase in production as illustrated on Platt Exhibit 8. The examiners commend this exhibit to the Commissioners for special attention. It is clear from the production history graph that the natural decline curve from 1961 to 1971 was arrested by new oil well drilling on the ranch. These are high GOR wells, the 1985 average being 30,000:1. (Tr. 670 line 13). [Averages can be misleading, but in this case they are not. Analysis of Platt exhibit 25 shows that 67 out of 156 leases on the ranch have projected average per well recoveries below 10,000 barrels. GOR figures are reported for 57 of these wells with the *median* being about 37,500:1. The *median* reported GOR for all wells is about 27,000:1] Mr. Platt, consulting petroleum engineer for the ranch, testified that it was not necessary to exceed a GOR of 30,000:1 for technical reasons to recover these reserves (Tr. 670 line 25). The impetus for high gas production seems to stem rather from economic requirements. Platt Exhibit 26 illustrates the dilemma faced by one who is making a drill/no drill decision for typical oil well on the ranch; cumulative gas revenues are projected some three times higher than oil revenues; and seem to be required for eco-

nomic payout. There is no incentive to minimize GOR under these circumstances, but it cannot be disputed that these high GOR wells result in the production of oil which would not otherwise occur on a primary recovery basis.

Based on the evidence submitted by Mr. Platt the examiners recommend that the "Soule 5000' proposal (a 5000:1 casinghead gas limit applied against actual production rather than top allowable) not be incorporated into the field rules as a strict limit, but as a guideline only (see appendix 1).

It appears from the evidence that many small oil operators in the field require casinghead gas production to justify the search for oil in a field which has reached an advanced stage of depletion, with many wells making only two or three barrels of oil per day. The average oil rate for new wells on the Burnett Ranch is 5 BOPD (Platt Exhibit 26), a level which will not even attract the interest of one major operator:

> "In-house we have basically identified to meet minimum economics we need at least 30 barrels or about 30 barrels a day. With money the way it is right now management is not too interested in minimum economics. They want a little additional gravy thrown in the pot, basically."
> (Melissa Symmonds, Tenneco, Tr. 6742)

What was true for this major operator in 1986 was true for another in 1935. Skelly Oil Company Vice-President Mr. Stallcup, speaking of some of his new wells in a pressure depleted area:

> "Those five wells averaged 33 or 35 barrels per day . . . and, in my judgment, they will never pay unless we find some new method of cracking the oil."
> (Transcript page 144, Hearing of November 13, 1935, CIG Exhibit 1)

Although the major companies own substantial oil rights in the field, if Tenneco is typical it seems a safe assump-

tion that marginal economics requirements for all of the majors are higher than those for 15-well independents.

Field Rules as a Risk-Incentive Policy

Celeron submits that prospectors for remaining oil in the field should be "encourage(d) to take risks" with relaxation of perforation restrictions an appropriate measure in this regard. Some of the new wells in Moore County are not commercial for oil alone—a sample examined by Mr. Gillespie had average peak rate production of 7 BOPD with quick decline curves such that ultimate recovery would be limited to a range of 5000 to 7000 barrels per well. (Tr. 8490). In comparison, Ronnie Platt calculated that on the Burnett Ranch, a drill/no drill cutoff of 9000 barrels was required *with* a producing GOR of 30,000:1 for a commercially viable completion. (Platt Exhibit 26).

"Commercial" was defined by Mr. Gillespie as that which "would permit the recovery of the drilling and completion costs." (Tr. 8944) He further stated "I would say that if an operator could produce at least at a level that would recover the amount of lease operating expenses plus some profit, which would ordinarily be one to two barrels of oil per day per well, that that would be one of the tests for commerciality." (Tr. 9081). Mr. Gillespie was questioned by Counselor Sullivan and Examiner Osborn about Moore County oil economics as follows:

> Sullivan: But the stream of income that you're talking about in the instance of Moore County is just that; it's just the oil stream of income. Is that correct?
>
> Gillespie: "Yes. However, if one adds an increment of oil recovery—I mean, of gas recovery that would average 5,000 cubic feet per barrel over the life of the well, by my estimate one still would require on the order of slightly more than 20,000 bar-

rels of oil to recoup direct investment and operating expenses for that well.

If you add an increment over the life of the well of 10,000 cubic feet per barrel, 18,000 barrels or thereabouts would be required to recover the drilling, completion and operating expenses for the well."

Osborn: May I ask what prices you're using for oil and gas in your calculation, sir?

Gillespie: Yes, sir. $18 a barrel for crude oil, $1.25 for gas price, $200,0000 to drill and complete a well, $800 per well per month to operate, ten years for an estimated life, which is perhaps too short." (Tr. 8966-8967)

The issue was pressed by Pat Long, counselor for movants:

Long: I am interested in your scenario that if you are only producing a quarter of a barrel of oil out of zone A and a significant amount of gas, that you would recommend that that be plugged off. Could you tell me if that was done, how the oil that would be up there in whatever quantity would be produced?

Gillespie: It probably wouldn't be, because, in my judgment, there is so little oil there it is not commercial to recover, anyway. That would qualify as a resource, and in my understanding, there is a very, very big difference between the term resource and reserve. A *reserve* is a quantity that can be produced, under existing economic and technological circumstances. A *resource* is something that may be there but cannot be recovered under existing economic and technological circumstances. (Tr. 9100 line 21—9101 line 11, emphasis supplied).

* * *

Long: The problem I am having with substantial quantities, if we are interested in trying to maximize the total amount of hydrocarbons produced

from this field, wouldn't we perforate and produce zone A if it is recovering producible oil, regardless of the amount?

Gillespie: Not necessarily, no. If, for example, your question leaves the magnitude wide open and at 1/100 of a barrel of oil per day, the answer is absolutely no. If it were producing 100 barrels of oil per day, the answer is absolutely yes. (Tr. 9102 line 17—9103 line 1).

Dr. MacDonald, petroleum engineer for movants, supported perforation freedom and a high casinghead gas limit as an incentive to operators for completion of low volume oil wells.

MacDonald: "We're trying to encourage production here. Four barrels a day is a lot more than zero barrels a day. And if somebody can go out there and produce four barrels a day, I'm sure that anybody who goes out there and drills would like to get a lot more than that. But they are the risk takers.

What you're asking is that we don't allow people to take risks to recover hydrocarbons. We just say, 'We'll take care of you. Don't risk it.' And I feel we have to have people that are willing to risk. And if they go out there and don't hit the 60 barrels per day, but do hit 4 barrels per day, I think they should be allowed to produce them."

Schennkan: If they're making four barrels of oil and 350 mcf of gas per day, wouldn't you at least suspect, Dr. MacDonald, that they're probably producing significant quantities of gas that's not necessary for the production of oil?

MacDonald: You would have to take it on a case by case basis . . ." (Tr. 6604-6605)

Bill Murray, consultant for movants, similarly supported a high gas limit and perforation freedom as an economic inducement for completion of new oil wells:

Murray: "I'm talking about the incentive . . . prospectively to get these hundreds of billions (sic) of barrels of oil that we think we can get and to complete down as efficiently as possible." (Tr. 221)

* * *

Small: "Well, actually what you're giving on an incentive is in gas, not in oil?

Murray: I'm going to have the gas be the limiting factor . . . when I produce so much gas, it's however much oil I can produce up to that."
(Tr. 227)

* * *

Small: "You're asking the Commission to give certain incentives and to let oil operators have a bigger share of the gas, and that gas is obviously going to have to come from the gas that otherwise would be produced by the gas wells.

Now, how do you balance the rights where you're taking from one and giving to the other just as an incentive, an economic incentive to drill wells?"

Murray: "If it's accomplishing conservation. . . . It's a terrible situation to have the rights separated, but they exist that way, and I don't thing the Commission can just put their hands over their eyes and say 'We won't go after conservation because of this complex correlative rights problem'."
(Tr. 246-247)

Non-movants take a rather critical approach to this risk-incentive theory. Counselor Soule: "While they may not openly say so, the basic premise of the other side's case is to requset that the Commission give them gas which does not belong to them in order to make their otherwise uneconomical oil wells economical as a result of gas revenues." (Tr. 7024).

Regardless of one's philosophy on risk incentives, it is *particularly troublesome* to note that in 1986 some 27% of the casinghead gas in the field was being produced by

former LTX wells, which comprise only about 5% of the total oil wells in the field. (Tr. 5318 line 9, 5320, math: 500 divided by 10,796 = 4.6%). It is further troublesome to note that slightly over 70% of all casinghead gas in the field is being produced from 14.4% of the producing wells. (Tr. 8853). Special attention is directed to Appendix 3 for the proposition that excessive amounts of "casinghead gas" are being produced by some operators. If all were as it should be in the Panhandle Fields, the list of top 10 oil producers should correlate somewhat with the list of top 10 casinghead gas producers, indicating that produced casinghead gas was "indigenous to an oil stratum and produced from the stratum with oil" as required by Section 86.002(11) of the Texas Natural Resources Code. That Mr. Gordon Taylor, with 26 "oil" wells, should be producing more casinghead gas than Phillips Petroleum, with 654 oil wells, is a fact signalling some extremely aggressive "oil" completions in recent years. (Gillespie exhibits 63D-F set forth in Appendix 3). To permit such rapid and disorderly depletion of the remaining upper gas so as to econmically enable primary recovery of deeper oil would not be consistent with the § 86.097 requirement of the Texas Natural Resources Code. The new operators argue that without freedom from perforation restriction and ability to produce upper gas, the remaining oil will go unrecovered and thus be wasted. However, no primary recovery technique produces all reserves in place, and some of the oil left behind now may be recovered in future years when secondary recovery technology and product economics are more favorable. It is premature to condemn the producibility of remaining oil reserves in this field.

Conclusion

The examiners take the position that while encouragement of exploratory risk should be a goal of this Commission, it must be tempered by the peculiar nature of correlative rights conflicts in this field, which are specifi-

cally protected by a statute designed as a specific response to problems in this *field.* § 86.097 of the Natural Resources Code states in plan language: "No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only." Regardless of Commission policy goals, we are not free to disregard statutory law. Our Supreme Court has stated the rule:

> When the Legislature acts with respect to a particular matter, the administrative agency may not so act with respect to the matter as to nullify the Legislature's action even though the matter is within the agency's general regulatory field. There is little case law announcing the rule last stated, no doubt because it is self-evident.

State v. Jackson, 376 S.W.2d 341, 344-345 (Tex. 1964). In accord with this principle, the Texas Administrative Procedure Act states that courts shall reverse or remand any case in which "the administrative findings, inferences, conclusions or decisions are in violation of constitutional or statutory provisions." TEX. REV. CIV. STAT. ANN. art 6252-13a 19(e)(1) (Vernon Supp. 1987). We are bound by the Natural Resources Code to retain the historic Panhandle Field Rules prohibition against completion of oil wells in a dry gas horizon.

OTHER PROBLEMS

Reporting of Natural Gas Liquids

Some gas wells in the Panhandle produce very small amounts of liquid condensate byproducts commonly referred to as "drip".

> "In our country in the early '50s, the common thing was that everybody in the general area burned the drip. They knew where all the drips were, and they burned it in their car." (Max. Banks, Tr. 962).

In recent years the Commission has received complaints that some gas wells are making excessive condensate which is either produced to the plant without separation, or separated on the lease and moved secretively to Oklahoma for blending with crude oil (unsworn testimony of L. C. Shelton).

In response to complaints by a group which Ron Slover organized, the Commission in 1985 performed tests on 71 West Panhandle field gas wells and found that the wells produced on average slightly more than ½ gallon of condensate per day, or about ⅓ barrel per month. Mr. Slover appeared at this hearing to press his case for a Commission requirement that separators be required on all gas wells, but stated in unsworn testimony that he had not even asked to see the report which the Commission went to so much trouble to generate upon his complaint! (Tr. 935). His criticism: "most of those tested were conducted during the summer (and) . . . the so-called separators which were used were not of sufficient capacity to separate the liquid hydrocarbons from the gas." (Tr. 934). The record reflects a number of winter tests, as Mr. Slover would have seen had he ordered a copy of the District 10 report.

In June of 1986 the cumulative total of all liquids produced from some 3500 active gas wells was approximately 100 barrels. (Tr. 5140). J. B. Herrmann, operator witness for movants, operates about 10 gas wells and testified that none of them produced a sufficient amount of liquids to merit installation of separation equipment. (Tr. 3094-3095). He stated that the custom in the field was to remove these liquids instead with drips on the gathering lines. (Tr. 3095). J. B. Watkins, another operator witness for movants, also operates gas wells and likewise has no separators on them. (Tr. 3951). He stated that he thought it might be necessary to operate separators on wells in some areas of the field, but when questioned on this could not name any such area or wells. (Tr. 3951).

Miles Reynolds, chemical and petroleum engineer witness for movants, testified that most Panhandle Field gas must be boosted to buck transmission line pressure and any entrained liquids not removed before hand would damage transmission equipment.

> Q. "Is it common to find an inlet scrubber before the compressors to remove any liquids before the well stream—gas stream reaches the compressor?
>
> A: Yes. That's a fairly standard piece of equipment.
>
> Q: What would happen if liquids were entrained in that gas at the time it reached the compressor?
>
> A: It would be trapped by such a device. That's the purpose of it.
>
> Q: Would it cause damage to the compressor if liquids reached the compressor?
>
> A: Yes. Oh, very definitely." (Tr. 6063-6064)

The examiners suspect that human nature will assert itself in continued suspicions regarding gas well separation equipment. We suggest that as in the past, these complaints be referred to the District 10 office for processing.

Undercover Removal of Natural Gas Liquids

L. C. Shelton, in unsworn testimony, stated that some operators were secretively removing gas condensate liquids from their leases and transporting them across the Oklahoma line for blending with crude oil as a stabilizing agent.

In 1983 the Texas Legislature enacted Chapter 114 of the Natural Resources Code concerning regulation of trucks carrying liquid hydrocarbons. All such transporters are required to carry a cargo manifest identifying source and amount of volumes collected, including lease name, operator name, quantity removed, time loaded, and

intended point of destination including the name of the receiving facility. The law provides:

> "The Commission, its designated agents or employees, or a peace officer may examine a cargo manifest, whether it is on an oil tanker vehicle or in the records of the transporter, under circumstances where the examination is a lawful attempt to determine whether this chapter is being violated."
> V.T.C.A. Natural Resources Code § 114.101

Falsification of a cargo document is a criminal offense.

If Mr. Shelton or others in the field observe practices of this nature they consider suspicious, they should make a written report on the District 10 office with a copy to the local sheriff or deputy in charge of the area. This report should include a full description of the incident with license plate number or RRC number of the gathering vehicle, and specifically request a Section 114 Tex. Nat. Res. Code (Statewide Rule 85) investigation.

Daily Casinghead Gas Limit

The examiners recommend that the daily casinghead gas limit be readjusted. The limit has been changed on three prior occasions to reflect differing production rates and ratios, and it seems now proper to adjust it again. The last change was in 1941, when the limit was lowered from 775 mcf/d to 500 mcf/d. (CIG Exhibit 6 tab 52). The examiners believe a limit of 120 mcf/d as proposed in the notice of hearing is now appropriate and should be enacted. This figure is calculated by application of the normal Statewide multiplier of 2000:1 against the top allowable of 60 barrels of oil per day, which results in a daily casinghead gas limit of 120 mcf per well. Ronnie Platt, engineer for the Burnett Ranch interests, movants, stated.

> "I believe there's no question that it [his recovery forecast] could be obtained with the existing 500 gas

> limit under the existing rules, but I believe that the operators could probably achieve these same results or very close to these results with the gas limit as proposed by the Commission in their notice of hearing." (Tr. 553)

The Burnett Ranch interests have some 110,000 acres of oil *and* gas rights. In the eyes of the examiners, this factor tends to give Mr. Platt's testimony some measure of impartiality or neutrality on the issue of daily gas limits.

J. B. Watkins testified that a 120 mcf/day limit would not affect any of his existing wells. (Tr. 3990). Clark Gillespie analyzed some 11,000 W-10 filings and determined that 95% of the individual oil wells reported daily casinghead gas capacity at or below 120 mcfd. (Tr. 8810). This leaves some 500 to 600 wells above the proposed limit on an individual basis, but if lease averaging is permitted to continue, many of these will be unaffected. Dr. MacDonald testified that a reduction in casinghead gas production would have an exactly proportional reductionate effect on liquids production. (Tr. 6367). No evidence or test results were submitted in support of this assertion, and the examiners firmly disagree with the conclusion. We suggest that placing a high casinghead gas producing well on a time clock to give intermittent production will allow the wellbore time to load up with fluids between cycles and minimize excess casinghead gas production. Alternatively, cycling or re-injection of excess casinghead gas should be considered if production of over 120 mcfd/well is absolutely necessary for the recovery of oil. (Tr. 8846). The oil portion of this reservoir is in an advanced stage of depletion. A reduction in casinghead gas withdraws *and* a reduction of gas well gas withdrawals from zones below or within the gas-oil contact or transition zone will prolong the producing life of the oil field and add to recoverable reserves.

FINDINGS OF FACT

1. The proceedings in this docket were duly initiated pursuant to a notice issued January 9, 1986 by the Railroad Commission of Texas, and all affected operators received notice of the same as required by the Commission's Rules of Practice and Procedure and by the Administrative Procedure and Texas Register Act.

2. All persons seeking to become parties to this proceeding were given the opportunity to file a statement and argue on behalf of their request to be named as a party.

3. The proceedings in this docket and the hearing and record thereof are properly before the Railroad Commission of Texas.

4. A prehearing conference was held in this case on December 18, 1986, and proceedings to present evidence commenced on January 6, 1987.

5. The Railroad Commission called this hearing to review existing rules and to consider adopting new or amended rules for the Panhandle Carson County Field; Panhandle Collingsworth County Field; Panhandle Potter County Field; Panhandle Gray County Field; Panhandle Hutchinson County Field; Panhandle Moore County Field; Panhandle Wheeler County Field; Panhandle West (Sanford) Field; Panhandle West (Tubbs) Field; Panhandle (Osborne Area) Field; Panhandle, East (Albany Dolomite, Lower) Field; Panhandle, West Field; and Panhandle, East Field in Carson, Collingsworth, Gray, Hutchinson, Moore, Wheeler, Potter, Oldham, Sherman, and Hartley Counties in Texas. These fields collectively are referred to as the Panhandle Fields.

6. The Panhandle Carson County Field; Panhandle Collingsworth County Field; Panhandle Potter County

Field; Panhandle Gray County Field; Panhandle Moore County Field; Panhandle (Osborne Area) Field and Panhandle Wheeler County Field are designated by the Commission as oil fields.

The Panhandle, West (Sanford) Field; the Panhandle, West (Tubbs) Field; the Panhandle, East (Albany Dolomite, Lower) Field; the Panhandle, West Field; and the Panhandle, East Field are designated by the Commission as gas fields.

7. The Panhandle Oil Field (by various county designations) has been regulated as a separate field under special rules promulgated in orders pricipally adopted during the 1930s and 1940s. Most of the basic special field rules are set forth in Division Two of Oil and Gas Circular 16-B (October 17, 1933), special Order Fixing Allowable Production of Sweet and Sour Natural Gas in the Panhandle District of Texas (December 10, 1935), Order No. 20-169 (November 18, 1937), and Order No. 10-3087 (November 13, 1941). (Tr. CIG Exhibit 6, Tab 15, Tab 28, Tab 35, and Tab 53; Stumpf Exhibits 9A and 9B.)

The West Panhandle Gas Field and East Panhandle Gas Field have been regulated as separate non-associated gas fields under special rules promulgated in various orders entered from the late 1940s through the early 1950s. (Tr. CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108 [December 10, 1935]; Stumpf Exhibits 9A and 9B.)

8. The discovery oil well in the Panhandle Field was the Gulf Production Company S. B. Burnett No. 2 well in Carson County. This well was drilled in 1920 and completed in 1921 with an initial pumping potential of 175 barrels per day. (Tr. 286-287; Stumpf Exhibit 4).

The discovery gas well in the Panhandle Field was the Canadian River Gas Company Masterson No. 1

well in Potter County, now known as the Colorado Interstate Gas Company Masterson C-1 well. This well was drilled in 1917 and completed in 1918 with an initial potential of 4.8 million cubic feet of gas. (Tr. 283-285; Stumpf Exhibit 3).

9. In mid-1986 there were approximately 10,796 producing oil wells and 3510 producing gas wells in the fields. Cumulative production to that point was approximately 1.245 billion barrels of oil, 6.4 trillion cubic feet of casinghead gas and 31 trillion cubic feet of gas well gas. (Johnston Exhibit 11, Johnston Exhibit 5, Tr. 6424, Gillespie Exhibit 10).

10. Remaining producible oil reserves total at least 100 million barrels with current primary recovery technology. There is a substantial additional amount of oil in place not commercially producible under current primary recovery technology and economic conditions. (Gillespie Exhibit 5).

    Remaining gas well gas reserves are approximately 2.8 trillion cubic feet. (Gillespie Exhibit 10).

11. Five separately identifiable geologic rock formations may be encountered in the Panhandle Fields: The Brown Dolomite, the Moore County Lime, the Arkosic Dolomite, the Granite Wash, and the Granite or Basement (sometimes called Fractured Granite or Weathered Granite). (Tr. 7042-7043, 2268, 4029-4030, 7957.) These formations are sometimes segregated by impermeable shale barriers, but are interconnected and pressure communicated at various points in the field. (Tr. 7964, 7829, 7385, 7389, 7442, 7494, 9076.) (Tr. 9076; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, p. 1 [December 10, 1935], Holmes Exhibit 3.)

12. The Brown Dolomite and in certain regional areas, the Moore County Lime are blanket formations containing potentially productive porosity intervals of

5% or greater extending laterally over wide distances. (Tr. 7064-7065, 7664, 7671, 7677, 7682; Bay Exhibits 72-78.) Panhandle Field formations lying below the Brown Dolomite are more erratic, and porosity distribution within those lower formations tends to be local and discontinuous. (Tr. 7062, 7444-7445, 7549-7551.)

13. Most of the oil development and production from the Panhandle Field comes from the northeastern flank of the field, where there is a heavy concentration of oil wells. There are scattered pockets of oil reserves in the remainder of the field, generally found in structural depressions and traps. (Tr. 7078-7080; Bay Exhibit 11.)

14. The upper zones of the Panhandle Fields generally produce only gas, while oil, if present at any depth, is usually found at or below 250 feet above sea level. (Tr. 8582, 8600, 8658, 9200, 3700, 7386-7388, Gillespie Exhibits 32 and 33; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, p. 355 [November 19, 1935]; CIG Exhibit 5, Bauer, Oil and Gas Fields of the Texas Panhandle, 10 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 733, 744 [August 1926]; CIG Exhibit 5, Cotner & Crum, *Geology and Occurrence of Natural Gas in Amarillo District, Texas,* 17 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 877, 886 [August 1933]; Moore County Royalty Owners Assoc. Cross-Examination Exhibit 4; Rogatz, *Geology of Texas Panhandle Oil and Gas Field,* 23 BULL. OF AM. ASSOC. OF PET. GEOLOGISTS 983, 986 [July 1939]; Herrmann Cross-Examination Exhibit 3; Hagy, *History of Development of General Geology of the Panhandle Field of Texas,* 12 PANHANDLE-PLAINS HISTORICAL REVIEW, p. 7 [1939].)

15. Operators can generally use information from drillers' logs, producing characteristics of surrounding

wells, selective tests of isolated intervals within the wellbore, wireline logs, core analyses, and geological samples, in addition to reference to structure and stratigraphy, in order to determine the gas-oil contact in an individual oil well. (Tr. 1120, 2322, 2939, 3173, 3660-3661, 4115-4116, 2939, 2218, 2324, 2460, 4021, 5046, 9104, 9106, 197, 8549-8550, 4115, 1129, 7920-7921, 3832, 2445, 2457, 4115-4116, 4130, 1182, 9091, 2322, 2622.)

16. Operators can avoid perforation of oil wells at horizons which produce only gas and can thereby maintain a low gas-oil ratio and/or low casinghead gas rate. (Tr. 5987, lines 1-8; 9008, line 21, line 6; 9070, lines 1-12; 8853; 6952, lines 9-14; Gillespie Exhibit 66; CIG Exhibit 1, Oil and Gas Docket No. 10-1322, pp. 175-176 [March 20, 1940].)

17. It is not physically necessary to perforate oil wells in upper gas-only intervals in order to recover deeper oil. (Tr. 8989-8990, 3425, 8737, 8868-8869; Gillespie Exhibit 54A.)

18. Production of gas from above oil in immediate proximity in an oil well dissipates reservoir energy thereby reducing ultimate recovery of oil and causing waste. (Tr. 8433, lines 15-20; 3695, lines 9-22; 9079, lines 11-15; 6377, line 21—p. 6378, line 5; Strickland Exhibit 18; CIG Exhibit 1, Oil and Gas Docket No. 108, *et al.*, pp. 115-116 [July 18, 1935]; Oil and Gas Docket No. 108, *et al.*, p. 140 [November 19, 1935]; Gillespie Exhibit 50, *Texas Panhandle Fields: A Study of Gas Wastage and the Feasibility of Returning Waste Gas to Reservoir*, p. 19 [August 1934]; CIG Exhibit 6, Tab 28, Oil and Gas Docket No. 108, pp. 4-5 [December 10, 1935]; CIG Exhibit 6, Tab 75, Oil and Gas Docket No. 10-36,290 [September 16, 1957].)

19. West and East Panhandle Field gas wells generally produce from higher gas-only intervals separated in some areas by shale barriers from any oil-productive intervals at the sites of the gas wells and/or are completed at some lateral distance from any oil-bearing porosity interval, and therefore for the most part do not withdraw reservoir energy necessary for production of oil. (Tr. 8958; 6986, lines 14-19; 8426-8431; Strickland Exhibits 17 and 18.)

20. Production of unnecessary upper gas interval gas through Panhandle Field oil wells drains reserves which properly lie within the assigned proration units of West and East Panhandle Field gas wells. (Tr. 8775, 8778-8779, 8788, lines 14-17, 6995, lines 10-21; Gillespie Exhibits 51, 56, 58-63c.)

21. Completion of oil wells below the dry gas interval in the oil-productive portion of the Panhandle Fields reservoir(s) causes oil wells and gas wells to drain different underground pore space and minimizes competition for the same hydrocarbons on overlapping oil and gas surface proration units. (Tr. 6908, lines 3-10.)

    More than 15,000 oil wells and gas wells have been drilled and are now producing under the Railroad Commission's regulatory system of assigning the same surface acreage to both oil wells and gas wells. (Tr. 2878, lines 9-18; 6908, lines 3-10.)

22. The Commission has zoned the Panhandle Field reservoir(s) into separate gas fields and oil fields. Commission field rules require that an oil well be perforated only in levels, sands or strata productive of oil. (Commission Docket 108 Order, December 10, 1935, CIG Exhibit 1).

23. In 1956, all operators in the field were notified by the Commission that perforation of an oil well "in

the dry gas zone" was "definitely in violation" of Railroad Commission rules. (Murray Cross-examination Exhibit 1).

24. Tex. Nat. Res. Code § 86.097 states:

> "No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only."

This statute was enacted by the Legislature as a part of H.B. 266 on May 1, 1935, in *specific response* to abusive practices in the Panhandle Fields. (Act of May 1, 1935, ch. 120, 1935, Tex. Gen. and Spec. Laws 318; Commission Docket 108 order, December 10, 1935, CIG Exhibit 1.)

25. Gas well gas produced from the Panhandle Fields generally contains an insufficient amount of entrained liquid to justify installation of separating devices. (Tr. 6063, line 12—6064, line 4; 4932; Slover Cross-Examination Exhibit 1.)

26. West Panhandle Field gas wells efficiently drain 640-acre proration units. (Tr. 8519, lines 12—8520, line 2; 6180, lines 9-12; 6778, lines 13-16; Gillespie Exhibit 11A-11E, 12, 13, 13A.))

27. A daily casinghead gas limit of 120 mcf per well as proposed in the hearing notice is calculated by multiplication of the statewide 2000:1 figure against the top field allowable of 60 barrels of oil per day. 95% of all oil wells in the field report daily casinghead gas capacity below 120 mcf, without benefit of lease averaging. (Tr. 8810).

28. New drilling of oil between 1978 and 1985 arrested a 20 year decline curve and resulted in the additional recovery of at least 20 million barrels of oil which probably would not have been recovered otherwise. Casinghead gas production from the field ap-

proximately doubled during this interval. (Johnston Exhibits 2 and 10, Tr. 5129).

29. Some 27% of the casinghead gas being produced in the field is coming from former LTX wells. 71.1% of all casinghead gas is being produced from some 14.4% of the oil wells in the field. (Tr. 5318, 8853).

30. Some oil operators are maximizing casinghead gas production for economic reasons by perforating up into gas only horizons. (Tr. 1196, 3105, 3107, 3638, 3904).

31. Since the enactment of comprehensive field rules in 1935, technological advances have radically changed wellbore completion techniques and analytical methodology. (Tr. 3917-3919, CIG Exhibit 1, May 11, 1936, p. 259; Gillespie Exhibit 27, Bay Cross-examination Exhibits 6, 20 and 25, Podzemny Exhibit 1).

CONCLUSIONS OF LAW

1. All action has been taken and all prerequisites fulfilled to invest the Railroad Commission with jurisdiction to decide this matter.

2. Sections 85.201, 85.202(b) and 86.081(a) of the Texas Natural Resources Code charge the Commission with the duty to regulate production of oil and gas in order to prevent waste and protect correlalative rights.

3. When faced with a conflict between its mandates of preventing waste and protecting correlative rights, the Commission is required to balance all competing considerations in resolution of the matter. The prevention of waste is to be weighted heavily in this balancing process as it is the primary goal of the Commission.

   Gulf Land Co. v. Atlantic Refining Co., 131 S.W.2d 73 (Tex. 1939).

Hawkins et al. v. Texas Co., 209 S.W.2d 338 (Tex. 1948).

Phillips Petroleum Company et al. v. American Trading and Production Corporation et al., 361 S.W.2d 942 (Tex. Civ. App.—El Paso 1962, writ ref'd n.r.e.).

Railroad Commission v. Manziel, 361 S.W.2d 560 (Tex. 1962)

Texaco, Inc. v. Railroad Commission, 583 S.W.2d 307 (Tex. 1979)

Railroad Commission of Texas v. Fain, 161 S.W.2d 498 (Tex. Civ. App.—Austin 1942, writ ref'd w.o.m.)

Marrs v. Railroad Commission, 177 S.W.2d 941 (Tex. 1944)

4. Section 86.095 of the Texas Natural Resources Code authorized the Commission to zone the Panhandle Field reservoir(s) into two separate fields, to which the same tract of surface acreage may be assigned. Such dual assignment of acreage should be continued in order to prevent widespread disruption of correlative rights.

5. Section 86.097 of the Texas Natural Resources Code prohibits the completion and perforation of Panhandle Field oil wells at horizons which are productive only of gas.

6. Section 86.012(a)(11) of the Texas Natural Resources Code defines waste to include "the production of natural gas from a well producing oil from a stratum other than that in which the oil is found" unless produced in a separate string of casing. TEX. NAT. RES. CODE ANN. § 86.012(a)(11) (Vernon Supp. 1986).

7. "Casinghead gas" is defined at Section 86.002(11) of the Texas Natural Resources Code as "any gas or vapor indigenous to an oil stratum and produced

from the stratum with oil." TEX. NAT. RES. CODE ANN. §86.002(11) (Vernon Supp. 1986).

8. The Railroad Commission must follow and enforce the provisions of the Texas Natural Resources Code. *State v. Jackson*, 376 S.W.2d 341, 344-345 (Tex. 1964); TEX. REV. CIV. STAT. ANN. art. 6252-13a § 19(e)(1) (Vernon Supp. 1987).

9. Appendix 1 to the Proposal for Decision is a guideline which establishes a rebuttable presumption that a qualified well is properly completed.

10. Charges and clarifications of rules in the Panhandle Fields are appropriate in light of "changed conditions", *Railroad Commission v. Aluminum Company of America*, 380 S.W.2d 599 (Tex. 1964).

11. Adoption of the proposed order is a conservation measure that is necessary to prevent waste and to protect correlative rights in the subject fields.

EXAMINERS' RECOMMENDATION

Based on the foregoing findings of fact and conclusions of law, the undersigned examiners recommend that the attached order be adopted by the Commission. This order restates the rule that perforation of oil wells in dry gas horizons is not permitted, reduces the daily casinghead gas limit to 120 mcf per well, consolidates various minor fields, and rescinds numerous obsolete orders.

Respectfully submitted,

/s/ George Singletary
GEORGE SINGLETARY
Senior Technical Examiner

/s/ William Osborn
WILLIAM OSBORN
Legal Examiner

WO:GS:bb:W25

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

OIL AND GAS DOCKET NO. 10-87,017

FINAL ORDER ADOPTING AND CLARIFYING RULES AND REGULATIONS FOR THE PANHANDLE CARSON COUNTY FIELD, PANHANDLE COLLINGSWORTH COUNTY FIELD, PANHANDLE POTTER COUNTY FIELD, PANHANDLE GRAY COUNTY FIELD, PANHANDLE MOORE COUNTY FIELD, PANHANDLE WHEELER COUNTY FIELD, PANHANDLE HUTCHINSON COUNTY FIELD, PANHANDLE, WEST (SANFORD), PANHANDLE, WEST (TUBBS), PANHANDLE (OSBORNE AREA), PANHANDLE, EAST (ALBANY DOLOMITE, LOWER) FIELDS, PANHANDLE, WEST FIELD AND PANHANDLE, EAST FIELD, HEREINAFTER REFERRED TO AS THE "PANHANDLE FIELDS".

The Commission finds that, after statutory notice in the above-numbered docket, the presiding examiners have made and filed a proposal for decision containing findings of fact and conclusions of law, which was served on all parties of record; and that this proceeding was duly submitted to the Railroad Commission of Texas at conference held in its offices in Austin, Texas.

It has come to the Commission's attention that confusion exists among some operators in the Panhandle Fields as to the applicability of the rules presently enforced by the Commission in the administration of oil and gas conservation matters in said fields, and more particularly in the methods of completion permitted for oil wells. So that the existing confusion may be eliminated, the Commission, after review and due considera-

tion of a Proposal For Decision in Docket No. 10-87,017 and the findings of fact and conclusions of law contained therein, hereby adopts as its own the findings of fact and conclusions of law as if fully set out and separately stated herein.

Therefore, IT IS ORDERED by the Railroad Commission of Texas that the historic classification and separation of Panhandle oil and Panhandle gas fields shall be retained; that the following fields shall be consolidated:

Panhandle East (Albany Dolomite, Lower) into Panhandle, East Gas

Panhandle, West (Sanford) into Panhandle, West Gas

Panhandle, West (Tubbs) into Panhandle (Red Cave)

Panhandle (Osborne Area) into Panhandle Wheeler County Oil;

that various obsolete docket 108 and other orders as listed below be rescinded; and that the following rules, in addition to such of the Commission's general rules and regulations as are not in conflict herewith, be and the same are hereby clarified and adopted to govern the drilling, completion and operation of wells in the Panhandle Fields:

Oil Field Rules

Rule 1. Panhandle Field oil wells are restricted to completion in horizons bearing producible oil, production from said horizons to be capable of passing a gas-oil ratio cutoff of 100,000:1 on isolated 72 hour test of the highest 50 feet perforated. No person in possession of or operating an oil well may produce from the oil well gas found in a horizon productive of gas only.

Rule 2. No oil well shall hereafter be drilled nearer than FOUR HUNDRED AND SIXTY SEVEN (467) feet to any well completed in or drilling

to the same reservoir on the same lease, unitized tract, or farm; and no well shall be drilled nearer than TWO HUNDRED AND THIRTY THREE (233) feet to any property line, lease line, or subdivision line; provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well; and the above spacing rule and the other rules to follow are for the purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned to the individual oil well for the purpose of allocating allowable oil production thereto shall be known as the prescribed proration unit. No proration unit shall consist of more than TWENTY (20) acres except as hereinafter provided, and the two farthermost points in any proration unit shall not be in excess of ONE THOUSAND FIVE HUNDRED (1500) feet removed from each other, provided, however, that in the case of long and narrow

leases or in cases where because of the shape of the lease such is necessary to permit the utilization of tolerance acreage, the Commission may, after proper showing, grant exceptions to the limitations as to the shape of the proration units as herein contained. All proration units, however, shall consist of continuous and contiguous acreage which can reasonably be considered to be productive of oil.

If after the drilling of the last well on any lease and the assignment of acreage to each well thereon in accordance with the regulations of the Commission there remains an additional unassigned lease acreage of less than TWENTY (20) acres, then and in such event the remaining unasigned lease acreage up to and including a total of FIVE (5) acres may be assigned to the last well drilled on such lease, or may be distributed among any group of wells located thereon, so long as the proration units resulting from the inclusion of such additional acreage meets the limitations prescribed by the Commission.

An operator, at his option, shall be permitted to form fractional units of TEN (10) acres, with a proportional acreage allowable credit for a well on such unit, with the two furthermost points of such TEN (10) acre fractional unit not greater than ONE THOUSAND ONE HUNDRED (1100) feet removed from each other.

An operator, at his option, shall be permitted to form fractional units of FIVE (5) acres, with a proportional acreage allowable credit for a well on such unit, with the two farthermost points of such FIVE (5) acre fractional unit not greater than SEVEN HUNDRED FIFTY (750) feet removed from each other.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that it the acreage to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled.

Rule 4. The top allowable for oil wells is set to be 60 barrels of oil per day (BOPD). The maximum daily oil allowable for each well shall be based 25% on acreage and 75% per well and will be equal to the summation of Twenty-five percent (25%) of top allowable multiplied by the ratio the number of acres assigned to the well bears to twenty (20) acres plus seventy-five percent (75%) of top allowable; thus, each well assigned twenty (20) acres will have a 60 BOPD allowable, each well assigned ten (10 acres will have a 53 BOPD allowable, and each well assigned five (5) acres will have a 49 BOPD allowable.

Rule 5. An oil well shall be allowed to produce a daily maximum of 120 mcf of casinghead gas when assigned 20 acres, 106 mcf of casinghead gas when assigned 10 acres, and 98 mcf of casinghead gas when assigned 5 acres.

Rule 6. Individual oil wells shall be tested annually on a schedule beginning in April and concluding in August. Operators will be advised of their test periods and procedures by the District 10 office.

Gas Field Rules

Rule 1. The division and boundary line between the Panhandle, East and Panhandle, West gas fields as set forth in docket 10-23,955 is retained.

Rule 2. No gas well in the Panhandle, West, field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line or subdivision line; No gas well in the Panhandle, East field shall hereafter be drilled nearer than SIX HUNDRED SIXTY (660) feet to an well completed in or drilled to the same reservoir on the same lease, unitized tract or farm, and no well shall be drilled nearer than THREE HUNDRED THIRTY (330) feet to any property line, lease line or subdivision line;

Provided, however, that the Commission will, in order to prevent waste or to prevent the confiscation of property, grant exceptions to permit drilling within shorter distances than herein prescribed, whenever the Commission shall have determined that such exceptions are necessary either to prevent waste or to prevent the confiscation of property. When exception to this rule is desired, application therefor shall be filed and will be acted upon in accordance with the provisions of Commission Statewide Rules 37 and 38, which applicable provisions are incorporated herein by reference.

The aforementioned distances in the above rule are minimum distances to allow an operator flexibility in locating a well; and the above spacing rule and the other rules to follow are for the

purpose of permitting only one well to each proration unit.

In applying this rule, the general order of the Commission with relation to the subdivision of property shall be observed.

Rule 3. The acreage assigned an individual non-associated gas well for the purpose of allocating allowable gas production thereto shall be known as a gas proration unit, and such acreage may be claimed for each non-associated gas reservoir independently of any other reservoir. No gas proration unit shall contain more than SIX HUNDRED FORTY (640) acres in the Panhandle, West field, or ONE HUNDRED SIXTY (160) acres in the Panhandle, East field except as hereinafter provided; and no such acreage shall be included in any proration unit formed or created subsequent to the effective date of this order and allocated to the well thereon unless the farthermost two points of the unit created by the inclusion of such acreage be not greater than EIGHT THOUSAND FIVE HUNDRED (8500) feet in the Panhandle, West field and FOUR THOUSAND FIVE HUNDRED (4500) feet in the Panhandle, East field; provided that tolerance acreage of ten percent (10%) shall be allowed for each unit so that an amount not to exceed a maximum of SEVEN HUNDRED FOUR (704) acres in the Panhandle, West field and ONE HUNDRED SEVENTY SIX (176) acres in the Panhandle, East field may be assigned, and each unit containing less than SIX HUNDRED (640) acres in the Panhandle, West field or ONE HUNDRED SIXTY (160) acres in the Panhandle, East field shall be a fractional proration unit.

All such proration units shall consist of continous and contiguous acreage which can reasonably be considered to be productive of gas.

Operators shall file with the Commission certified plats of their properties in said field, which plats shall set out distinctly all of those things pertinent to the determination of the acreage credit claimed for each well unless such filing has already been made; provided that if the acreage assigned to any proration unit has been pooled, the operator shall furnish the Commission with such proof as it may require as evidence that interests in and under such proration unit have been so pooled.

Rule 4: The daily allowable production of gas from individual gas wells completed in the Panhandle, West and East gas fields, shall be determined by allocating the allowable production, after deductions have been made for wells which are incapable of producing their gas allowables, among the individual wells in the following manner:

Ninety-five percent (95%) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the acreage assigned such well for allowable purposes bears to the summation of the acreage with respect to all proratable wells producing from the respective field.

Five percent (5%) of the total field allowable for each field shall be allocated among the individual wells in the proportion that the deliverability of such well, as evidenced by the most recent test filed to the Railroad Commission, bears to the summation of the deliverability of

all proratable wells producing from the respective field.

Rule 5. Separating devices are not required for gas wells completed in dry gas (gas only) horizons. On-lease separating devices (prior to metering) are required where gas wells are completed to depths productive of oil, or in any case where on-lease separating devices would recover over 12 barrels per year of condensate or hydrocarbon liquid. On-lease drip collectors or interceptors are permissible separating devices if all products separated are accurately reported in compliance with Statewide Rule 85 when removed from the lease. All condensate or hydrocarbon liquid production over 1 barrel per gas well per month recovered on the lease must be reported on the monthly production report.

Rule 6. Gas wells in the Panhandle, West field shall be tested in June, July and August of each year, with reports due September first. No test is required of gas wells in the Panhandle, East Field due to extremely low reservoir pressure.

Gas well test data shall be filed using forms G-1 and G-10 rather than forms G-10 and G-11.

General Rules

Existing and future oil wells meeting one of the criteria set forth in Appendix One to the Proposal For Decision in this docket will be presumed to have been properly completed. Operators shall have a period of one year to bring existing wells into compliance with Appendix One guidelines.

All operators electing to complete a new oil well or add perforations to an existing well such that no Appendix One guideline is met must make such note on their W-2

filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of oil, and shall indicate that the District Office was notified prior to testing and indicate whether or not testing was witnessed by the District Office.

Existing gas wells will be presumed to have been properly completed if they are no deeper than +250 feet (sea level datum), or the base of the Brown Dolomite, whichever is higher; except in the Appendix One Section Four areas where proper completion is presumed if above the higher of the base of the Brown Dlomite, or +350 or +450 feet (set level datum) in areas 4(a) and (b) respectively. Operators shall have a period of one year to bring existing wells into compliance with these guidelines. All operators electing to complete a new gas well to a depth lower than presumed proper or deepen an existing gas well below that depth must make such note on their G-1 filing and attach for the Central Records well file a summary of selective test data or other analysis supporting their completion as in a horizon productive of dry gas or gas only, and shall indicate that the District Office was notified prior to testing and indicate whether or not testing was witnessed by the District Office.

These requirements and guidelines are based on a Commission finding that gravity segregation of oil and gas in the Panhandle fields was generally efficient over geologic time such that in locations where there is both producible oil and free gas, the two are generally divided and separated according to their densities into lower oil intervals and upper gas intervals. For this reason, dual assignment of the same surface acreage to both the oil and the gas fields for recovery from two properly completed and classified wells, one for recovery of oil and the other for recovery of gas, shall be permitted to continue as it has since the inception of comprehensive field rules in 1935.

The special rules and directives set forth in Oil and Gas Docket 10-77,314 (LTX product reports and classification) and the related staff memorandum of September 24, 1985 are retained. The Staff Memorandum of December 17, 1973 (District 10—Lease-wide Testing) is rescinded. All other prior fieldwide rules, directives and memoranda are hereby superceded and rescinded, including but not limited to the following:

Date	Docket No.	Purpose
08/27/30	112	Establishing Field Rules
11/01/30	112	Amending 8/27/30 Order
01/23/31	112	Establishing Field Rules
04/04/31	113	Establishing Field Rules
10/13/31	108	Time limits on drilling
10/30/31	108	Establishing Field Rules
10/30/31	108	Common Purchaser Law
10/30/31	122, 119	Rules governing common purchasers
05/09/32	108	25% Open Flow Limit
06/15/32	None	Oil and Gas Circular 15
11/18/32	108	Granting Exemptions
12/06/32	108	Establishing Field Fules
12/30/32	108	Determining Allowable Production
12/30/32	108	Establishing Field Rules
10/17/33	None	Adopting Circular 16-B
05/12/34	108	Amending Rule 2
05/15/34	None	Readopting Circular 16-B
05/24/35	108	Reducing Potentials
07/20/35	108	Fixing Allowable Gas Production
08/01/35	108	Fixing Allowable Gas Production
08/05/35	108	Fixing Allowable Gas Production
08/06/35	108	Changing Method of Taking Potentials
08/28/35	108	Fixing Allowable Gas Production
09/25/35	108	Fixing Allowable Gas Production
10/17/35	108	Fixing Allowable Gas Production
10/23/35	108	Regarding Pending Court Proceedings
11/22/35	108	Changing Method of Taking Potentials
12/10/35	108	Fixing Allowable Gas Production
01/14/36	108	Authorizing Gas-Oil Ratio Survey
02/03/36	108	Amending Above

Date	Docket No.	Purpose
04/27/36	108	Revoking Authorization of Survey
09/15/36	108	Authorizing Gas-Oil Ratio Survey
02/25/37	108	Setting a Gas-Oil Ratio
10/02/37	10-93	Limiting Gas Volumes
11/18/37	20-169	Fixing Allowable Gas Production
05/04/38	10-316	Fixing Allowable Gas Production
05/25/38	10-338	Amending Above
10/15/38	10-453	Setting Out Rules
11/25/38	10-499	Limiting Gas Volumes
01/14/39	10-548	Amending Above
01/18/39	20-550	Classifying Condensate Wells
01/31/39	10-564	Fixing Allowable Gas Production
04/01/39	10-621	Supplementing Above
01/11/40	10-1222	Amending Circular 16-B
03/12/40	10-1384	Promulgating Spacing Rule
03/25/40	10-1449	Fixing Allowable Gas Production
03/28/40	10-1445	Amending Circular 16-B
04/30/40	10-1543	Suspending Above
07/08/40	10-1685	Repressurization of Oil Sands
08/23/40	10-1832	Amending Circular 16-B
11/20/40	10-2080	Fixing Classification Method
08/29/41	10-2898	Amending Circular 16-B
11/13/41	10-3087	Limiting Gas Volumes
04/06/42	10-3593	Limiting Gas Production
10/29/42	10-4135	Limiting Gas Production
05/19/43	10-4833	Limiting Gas Production
08/14/44	10-6600	Amending Spacing Rules
11/14/45	10-8333	West Pampa Repressurization
05/24/48	10-12,465	Requiring Well Tests
09/24/48	10-13,196	Sweet and Sour Gas
01/10/49	10-13,783	Amending Above
02/06/50	10-17,595	Amending Above
03/04/52	10-23,060	Determination of Absolute Potentials
12/19/51	10-22,479	Roughness Friction Factor
06/09/52	10-23,807	Amending Order No. 10-13,196
06/30/52	10-23,955	Rescinding Order No. 10-23,807
07/21/52	10-24,144	Amending Order No. 10-23,060
09/18/52	10-24,493	Gas Measurement Rules
05/19/54	10-29,542	Gas Well Testing Rules
05/19/54	10-29,544	Gas Well Testing Rules

Date	Docket No.	Purpose
08/30/54	10-30,121	Amending Rule 3(c)
11/07/55	10-32,363	Revising East Field Rules
09/16/57	10-36,290	Requiring Gas-Oil Ratio Surveys
11/22/60	10-44,633	East Field Operating Rules
10/11/77	10-67,681	GOR Test Procedures

Done this —— day of ————, 1988.

RAILROAD COMMISSION OF TEXAS

Chairman

Commissioner

Commissioner

ATTEST:

Secretary

WO:wo:Blank

[Appendices Omitted in Printing]